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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF COMPETITION IN THE)
PROVISION OF ELECTRIC SERVICES)
THROUGHOUT THE STATE OF ARIZONA.)
)

DOCKET NO. U-0000-94-165

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Richard Rosen on the Stranded Cost portion of the above-referenced Docket.

RESPECTFULLY SUBMITTED this 21st day of January, 1998.

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF	**)**	
COMPETITION IN THE	**)**	
PROVISION OF ELECTRIC	**)**	**DOCKET NO. U-0000-94-165**
SERVICES THROUGHOUT	**)**	
THE STATE OF ARIZONA	**)**	

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
The Residential Utility Consumer Office

January 21, 1997

TABLE OF CONTENTS

LIST OF EXHIBITS

Residential Utility Consumer Office

Executive Summary

This testimony is offered in response to Docket No. U-0000-94-165 on behalf of the Arizona Residential Utility Consumer Office (RUCO). The purpose of this testimony is to provide the Arizona Corporation Commission (ACC) with 1) public policy recommendations of key issues related to the calculation, sharing, and recovery of stranded costs, and 2) presentation of the "retail generation service" methodology for computing stranded costs. To illustrate RUCO's position, this testimony provides an initial calculation of stranded costs for Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), and the Salt River Project (SRP).

In response to the ACC's Eleven Policy Questions in this docket, the following are the conclusions reached in this testimony. This testimony advocates use of the "administrative valuation approach" for calculating stranded costs. This approach compares projections of the utility's revenues for electric generation if generation prices were deregulated, and projections of the utility's revenues for electric generation if generation prices were continued to be regulated based on the utility's embedded costs of generation. In calculating stranded costs, total *potentially* stranded costs (strandable costs) should be computed. An estimation of the market price for retail generation services is necessary to produce projections of the utility's revenues for electric generation. Therefore, the market price of power should be determined based on the average retail cost of power in the region to serve a particular load based on its load factor and other seasonal characteristics. Developing estimates of the market price of power should include the wholesale price, but should be based on the total retail price for generation services to the customer, which is equal to wholesale price plus a retail margin.

Stranded costs should include the following categories of costs that are currently being incurred by utilities: generation assets and generation operations and maintenance (O&M) costs, purchase power agreements, fuel contracts, generation-related regulatory assets and liabilities, and generation-related A&G. Stranded costs should be calculated using a time period of at least 15 years, and perhaps as much as 25 years, depending on the expected remaining operational life of the generation resources of a particular utility. The amount of stranded cost recovery from ratepayers should be calculated administratively and trued-up annually (or at least bi-annually) to account for the actual retail market prices of generation. The Affected Utilities should bring the embedded cost of generation closer to the market price for generation through appropriate mitigation measures *before* Arizona takes steps towards allowing recovery of stranded costs. The most important mitigation measures utilitities should take are those that focus on cost reduction.

If there are stranded costs, ratepayers and shareholders should share in paying for stranded costs. While the appropriate percentage of this sharing should be determined by the ACC, an initial 50/50 split is a reasonable approach. Payment by all ratepayers should be made through a non-bypassable, nondiscriminatory "wires" charge or competition transition charge (CTC) which would tie the collection of stranded generation costs to the continued use of transmission and/or distribution service. In determining the CTC, the economic generation and generated ancillary services should be separated from the uneconomic or stranded generation costs. The CTC stranded cost recovery mechanism should be administered to *all* retail customers in a distribution utility's service territory. Therefore, both customers on the standard offer service and those customers in the competitive market purchasing electric generation service from alternative suppliers should pay for stranded costs on the same basis.

The time frame for stranded cost recovery should be determined prior to commencing the recovery process. I recommend that the time frame not extend past the end of the transition period defined by the Competition Rules, i.e., January 1, 2003, unless it is determined during a true-up in 2002 that a large credit is due ratepayers because stranded costs are strongly negative. In that case, negative stranded cost recovery would have to continue for many years beyond 2003.

While stranded costs are being recovered, there should not be a rate freeze; there should be a rate reduction. However, a price cap on the generation rate is necessary during the transition to completely unregulated generation markets in order to protect ratepayers from any adverse effects of the unregulated generation market during this time period. The rate cap should be at or below the level that rates would have been under continued regulation. The rate reduction should result from setting the price of the standard offer service at a market-based price for retail generation services.

This testimony offers initial estimations of the magnitude of strandable generation costs that APS, SRP and TEP have. These estimations were reached through use of the Tellus stranded cost model (SCM). The Tellus SCM is a spreadsheet model which performs three independent analyses: an unbundling analysis, a market price analysis for retail generation services, and projections of potentially strandable costs over a specified period of time. Using utility-specific data from the most recent FERC Form 1, the model develops an estimate of a utility's unbundled costs of generation, transmission, distribution and customer costs that are reflected in the utility's average retail rate. The unbundled cost of generation, or retail generation services, is then compared to a market price for retail generation services in order to estimate potential stranded costs.

Under a Basecase APS, SRP, and TEP will have strandable costs over the period 1998-2020 of negative $838 million, negative $3.0 billion, and positive $513 million in 1998 present value dollars, respectively. If the calculation period is reduced to only 15 years (1998-2012), APS, SRP, and TEP will most likely have strandable costs in the range of positive $102 million, negative $834 million, and positive $779 million, respectively, in 1998 present value dollars. Thus, it is concluded that of these three utilities, only TEP may have any significant level of positive strandable costs. This is because the ratepayers have already paid off any uneconomic costs that previously existed on the APS and SRP systems. This implies that unless a negative stranded cost recovery charge is put into place for APS and SRP once retail competition begins, ratepayers may pay more for electricity over the subsequent 15 years and longer, under retail competition, than they would have paid if regulation were continued. It is also very important to note that the Basecase results indicate that after about 2003, the expected average retail price of power in the unregulated market will exceed the expected regulated price of generation for APS and SRP. This implies that ratepayers will likely pay more under retail competition after 2003 on an annual basis, than if regulation were continued. This forecast graphically illustrates the fact that if a negative stranded cost recovery charge is not put into place for APS and SRP ratepayers for up to 10 years, or there are no substantial productivity improvements as a result of competition, ratepayers may not benefit from retail competition.

However, RUCO anticipates that competition will benefit consumers because technological innovations and operational efficiencies will occur in the open market. Furthermore, the risk of paying for future operational efficiencies has been eliminated. Additionally, during the transitional period, under RUCO's proposal, residential consumers will be protected by a rate cap, a true-up, and the potential amortization of negative stranded cost.

In contrast, for TEP the ACC should establish a stranded cost recovery charge based initially on 50 percent of initial estimates of TEP's strandable costs reported in this testimony. The ACC should also investigate in TEP's utility-specific stranded cost docket the reasons for the existence of TEP's strandable costs, and should determine whether a lower percentage than 50 percent of TEP's strandable costs should be charged to ratepayers. If the ACC decides that ratepayers should pay for less than 50 percent of TEP's stranded costs, then the stranded cost recovery charge should be appropriately adjusted. Of course, the ACC should also true-up TEP's stranded cost recovery charge either annually, or at least bi-annually, as actual retail market price data becomes available. Any recovery of stranded costs by TEP should end by January 1, 2003, so that at least there is a probability that the rates for ratepayers in TEP's service territory will be lower after this date than they would have been under regulation.

Based on the findings and conclusions reached in this testimony, it is recommended that the Electric Competition Rules be modified regarding stranded costs. Specifically, it is recommended that changes be made to the Rules regarding the definition of stranded costs in Section R14-2-1601 (8). Changes should also be made to Sections A, B, H, I, J and L of R14-2-1607. No recommendations are offered for changes to Sections C, D, E, F, G, or K of R14-2-1607. Specific changes in the wording of each section of the Competition Rules is provided at the end of Section 6 of this testimony.

Additionally, it is recommend that the ACC follow-up this generic docket with utility-specific proceedings as provided for under the current Competition Rules this would allow the enclosed initial estimates of stranded costs to be refined. One reason this is necessary is because the ACC has not yet reviewed and ruled on the issue of what the unbundled rates for the Affected Utilities should be. Yet, the proper calculation of stranded costs should include the final ACC ruling on the magnitude of the generation portion of current rates as a starting point. A second reason is that these initial calculations of stranded costs have not had the benefit of information that would have obtained through discovery that might allow the refinement of certain input assumptions used in calculations of stranded costs herein.

1. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from M.I.T., an M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resource, and environmental research. Within Tellus Institute, the Energy Group focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON TELLUS' EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. The Energy Group has had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. Tellus Institute also has reviewed the prudence of many past supply planning decisions by utilities.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 16 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-

Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec.

Due to my extensive regulatory experience in the public interest, as outlined above, in 1988 I was chosen to serve a 3-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, within the last 2 years, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the National Association of Regulatory Utility Commissioners (NARUC), the New England Governors' Conference, and the National Council on Competition in the Electric Industry.

In the last 2 years, I have spent most of my time analyzing electric utility restructuring issues. I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to the ConEd's, NYSEG's, and RG&E's restructuring plans. I also have worked or testified on other restructuring issues in Nevada, New Mexico, New Jersey, Illinois, Pennsylvania, New York, and Michigan. The remainder of my experience is summarized in my resume, which is attached as Exhibit RAR-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. In this case, I am testifying on behalf of the Arizona Residential Utility Consumer Office (RUCO).

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS DOCKET?

A. No, I have not testified previously in this docket.

Q. WOULD YOU PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY IN THIS DOCKET.

A. Yes. The purpose of my testimony in this docket is to provide the Arizona Corporation Commission (ACC) with: 1) public policy recommendations on key issues related to the calculation, sharing, and recovery of stranded costs, and 2) presentation of the "retail generation service" methodology for computing stranded costs. To illustrate RUCO's position, I have also done an initial calculation of stranded costs for Arizona Public Service Company (APS), Tucson Electric Power Company (TEP), and the Salt River Project (SRP),

Q. HAVE YOU TESTIFIED ON STRANDED COST ISSUES BEFORE?

A. Yes, I have. On behalf of the Texas Office of Public Utility Counsel (Case No. 473-96-2285), I testified before the Texas Public Utilities Commission on public policy recommendations on key issues related to the calculation, sharing, and recovery of stranded costs. On behalf of the American Association of Retired Persons (AARP), I testified before the New York Public Service Commission on key issues related to stranded costs in proceedings for New York State Electric and Gas Corporation (Case No. 96-E-0891), Consolidated Edison Company of New York, Inc. (Case No. 96-E-0897), and Rochester Gas and Electric (Case No. 96-E-0898). On behalf of AARP, I also testified before the Public Utilities Commission of New Hampshire on how to structure pricing to implicitly share stranded costs for the purposes of that State's retail access pilot programs (DR 96-150).

I have also testified before many public service commissions (in Kansas, Massachusetts, Michigan, Missouri, New Hampshire, New York, Pennsylvania, and Vermont) in many cases regarding the ratemaking treatment of uneconomic costs associated with nuclear and coal plants constructed during the 1970s and early 1980s. In fact, about 15 years ago, Tellus Institute originated the concept of "economic excess capacity," a concept that is basically the same as what has now become known as "stranded costs" or "excess cost over market." Thus, I have testified on many stranded cost-related issues over the last 15 years.

Q. HAVE YOU TESTIFIED ON ANTI-COMPETITIVE ISSUES BEFORE?

A. Yes, I testified on market power issues in the proposed merger of Central Illinois Public Service Company (CIPS) and Union Electric Company (UE) before the Illinois Commerce Commission on behalf of the Illinois Citizens Utility Board (Docket No. 95-0551), and before the Missouri Public Service Commission on behalf of the Missouri Office of the Public Counsel (Docket No. EM-96-149). I also testified before the Maryland Public Service Commission (Docket No. EC96-10-000) and before the Federal Energy Regulatory Commission (Docket No. 8725) on behalf of the Maryland Office of People's Counsel regarding the proposed merger between Baltimore Gas & Electric Company (BGE) and Potomac Electric Company (PEPCO). Finally, in New York Case Nos. 96-E-0891, 96-E-0897, and 96-E-0989, I also testified on market power and market structures.

Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

A. The remainder of this testimony is organized into five major sections:

2. Summary of Conclusions and Recommendations
3. Background
4. Stranded Cost Methodologies
5. Stranded Cost Results
6. Stranded Cost Policy

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. My findings and conclusions on the ACC's Eleven Policy Questions are as follows:

- Stranded Costs should be calculated using the "administrative valuation approach", which compares projections of the utility's revenues for electric generation if generation prices were deregulated, and projections of the utility's revenues for electric generation if generation prices were continued to be regulated based on the utility's embedded costs of generation. This is equivalent to a market valuation approach if the same projection of market prices is assumed.
- The stranded cost methodology should compute total potentially stranded costs (<u>strandable</u> costs).
- The market price of power should be determined based on the average retail cost of power in the region to serve a particular load based on its load factor and other seasonal characteristics. Developing estimates of the market price of power should include the wholesale price, but should be based on the total retail price for generation services to the customer, which is equal to wholesale price plus a retail margin.
- Stranded costs should include the following categories of costs that are currently being incurred by utilities: generation assets and generation operations and maintenance (O&M) costs, purchase power agreements,

fuel contracts, generation-related regulatory assets and liabilities, and generation-related administrative and general (A & G) expenses.

- Stranded costs should be calculated using a time period of at least 15 years, and perhaps as much as 25 years, depending on the expected remaining operational life of the generation resources of a particular utility.
- The amount of stranded cost recovery from ratepayers should be calculated administratively and trued-up annually (or at least bi-annually) to account for the actual retail market prices of generation.
- The Affected Utilities should bring the embedded cost of generation closer to the market price for generation through appropriate mitigation measures *before* Arizona takes steps towards allowing recovery of stranded costs.
- Ratepayers and shareholders should share in paying for stranded costs, if there are any. While the appropriate percentage of this sharing should be determined by the ACC, a 50/50 split is a reasonable approach. Payment by ratepayers should be made through a non-bypassable, nondiscriminatory "wires" charge or competition transition charge (CTC) which would tie the collection of stranded generation costs to the continued use of transmission and/or distribution service.
- The time frame for stranded cost recovery should be determined prior to commencing the recovery process. I recommend that the time frame not extend past the end of the transition period defined by the Competition Rules, i.e., January 1, 2003, unless it is determined during 2002 that a large credit is due ratepayers because stranded costs are strongly negative.

- While stranded costs are being recovered, there should not be a rate freeze; there should be a rate reduction, with the price of the Standard Offer Service being set based on the market price of retail generation services. However, a price cap on the generation rate is necessary during the transition to completely unregulated generation markets in order to protect ratepayers from any adverse effects of the unregulated generation market during this time period. The rate cap should be at or below the level that rates would have been under continued regulation.

Q. WHAT CONCLUSION DID YOU REACH AS TO THE LIKELY MAGNITUDE OF THE STRANDABLE GENERATION COSTS THAT APS, SRP, AND TEP HAVE?

A. Using the Tellus stranded cost model, I have found that under my Basecase or most likely assumptions APS, SRP, and TEP will have strandable costs over the period 1998-2020 of negative $838 million, negative $3.0 billion, and positive $513 million in 1998 present value dollars, respectively. If the calculation period is reduced to only 15 years (1998-2012), APS, SRP, and TEP will most likely have strandable costs in the range of positive $102 million, negative $834 million, and positive $779 million, respectively, in 1998 present value dollars. Thus, I have concluded that of these three utilities, only TEP may have any significant level of positive strandable costs. This is because the ratepayers have already paid off any uneconomic costs that previously existed on the APS and SRP systems. This implies that unless a <u>negative</u> stranded cost recovery charge is put into place for

APS and SRP once retail competition begins, ratepayers may pay more for electricity over the next 15 years and longer, under retail competition than they would pay if regulation were continued. Note that an administratively determined negative stranded cost recovery charge is equivalent to selling the generating units of a particular utility at above net book value, and passing the profit through as a credit to the ratepayers by reducing the existing ratebase. This is what should happen if a sale at above book value were to occur.

In this regard, it is also very important to note that my Basecase results indicate that after about 2003, the expected average retail price of power in the unregulated market will exceed the expected regulated price of generation for APS and SRP. This implies that ratepayers will likely pay more under retail competition after 2003 on an annual basis, than if regulation were continued. This forecast graphically illustrates the fact that if a negative stranded cost recovery charge is not put into place for APS and SRP ratepayers for up to 10 years, or if there is no substantial operating or technological-based cost reductions as a result of competition, ratepayers may not benefit from retail competition.

Q. WHAT ARE YOUR RECOMMENDATIONS TO THE ACC BASED ON YOUR FINDINGS AND CONCLUSIONS SUMMARIZED ABOVE?

A. I recommend that the Electric Competition Rules be modified regarding stranded costs. Elaboration of the specific changes recommended are contained at the end of Section 6 of this testimony.

- Specifically, I recommend the following changes to the Rules: I recommend changing the definition of stranded costs in Section R14-2-1601 (8). I believe changes should also be made to Sections A, B, H, I, J and L of R14-2-1607.
- I have no recommended changes to Sections C, D, E, F, G, or K of R14-2-1607.

In addition, I recommend that the ACC follow-up this generic proceeding with a set of utility-specific proceedings to determine the actual strandable costs of each utility, as the current competition rules provide for. This would allow my initial estimates of stranded costs to be refined. One reason this is necessary is because the ACC has not yet reviewed and ruled on the issue of what the unbundled rates for the Affected Utilities should be. Yet, the proper calculation of stranded costs should include the final ACC ruling on the magnitude of the generation portion of current rates as a starting point. A second reason is that my initial calculations of stranded costs have not had the benefit of information that I would have obtained through discovery that might allow the refinement of certain input assumptions that I used in my calculations of stranded costs.

Q. BASED ON YOUR INITIAL ESTIMATES OF STRANDED COSTS, WHAT WOULD YOU RECOMMEND TO THE COMMISSION?

A. Based on my initial estimates of stranded costs, I recommend to the Commission that the total retail rates of all Affected Utilities be capped during the transition period January 1, 1999 through January 1, 2003, at the very least. This rate cap should ensure that ratepayers would not pay more under retail competition than they would have if regulated generation rates had continued throughout this period. I would also recommend, then, that during 2002, near the end of the transition period, the ACC should check as to whether it still seems likely that retail market prices for the post-2003 period will likely exceed the regulated price of generation. Generally, RUCO supports the concept of retail competition based upon two assumptions; that pressure from the marketplace will result in more efficient generating plant operations and technological innovations that will result in lower costs for consumers. RUCO fully anticipates that technological and operational efficiencies will occur in the open market. Furthermore, the risk of paying for future operational inefficiencies has been eliminated. Additionally, during the transitional period, under RUCO's proposal, residential consumers are protected by a rate cap, a true-up, and the potential amortization of negative stranded cost. However, if it is determined during a true-up process in 2002 that APS' and SRP's stranded costs will be significantly negative, and that the retail market price of power after 2003 will likely exceed the regulated generation price as I currently forecast, the ACC should credit ratepayers for the full amount of these negative stranded costs after 2003 if retail competition is put into effect.

In contrast, for TEP the ACC should establish a stranded cost recovery charge based initially on 50 percent of my initial estimate of TEP's strandable costs. In the utility-specific strandable cost proceeding for TEP, the ACC should also investigate in Phase II of this docket the reasons for the existence of TEP's strandable costs, and should determine whether a <u>lower</u> percentage than 50 percent of TEP's strandable costs should be charged to ratepayers. If the ACC decides that ratepayers should pay for less than 50 percent of TEP's stranded costs, then the stranded cost recovery charge should be appropriately adjusted. Of course, the ACC should also true-up TEP's stranded cost recovery charge either annually, or at least bi-annually, as actual retail market price data becomes available. Any recovery of stranded costs by TEP should end by January 1, 2003, so that at least there is a possibility that the rates for ratepayers in TEP's service territory will be lower after this date than they would have been under regulation.

3. BACKGROUND

Q. PLEASE PROVIDE BACKGROUND INFORMATION TO YOUR INVOLVEMENT IN THIS DOCKET.

A. The Arizona Corporation Commission ("ACC" or "Commission") issued Decision No. 59943 on December 26, 1996, approving new rules, A.A.C. R14-2-1601 through R14-2-1616 ("Rules" or "Electric Competition Rules"). The Rules provided for a phased-in transition to retail electric competition in Arizona, beginning on January 1, 1999. These Rules required the creation of special working groups to address several key issues related to the introduction of competitive power markets in Arizona. One group was the Stranded Cost Working Group, comprised of representatives of all stakeholders and coordinated by the Director of Utilities, as required by Rule R14-2-1607.C. The Stranded Cost Working Group contained three subcommittees: the Recovery Mechanism Subcommittee, the Calculation Methodologies Subcommittee, and the Accounting, Finance and Tax Subcommittee. The result of their work was *Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona.* On September 25, 1997, RUCO offered their response to the Stranded Cost Working Group report.

On August 29, 1997, the Commission issued Decision No. 60351 which reopened the Rules and directed the Hearing Division to produce procedural orders to establish hearings regarding aspects of electric utility competition. On

October 30, 1997, RUCO filed a Request for Evidentiary and Procedural Order. This procedural order, Docket No. U-0000-94-165, was issued on December 2, 1997 to set evidentiary hearings on generic issues related to stranded costs.

Q. WHAT GENERIC ISSUES RELATED TO STRANDED COSTS DID DOCKET NO. U-0000-94-165 REFER TO?

A. The generic issues the docket refers to cover the methodology, computation, mitigation, and recovery of stranded costs. It was ordered this testimony should cover the following issues:

1) Should the Electric Competition Rules be modified regarding stranded costs?
2) When should "Affected Utilities" be required to make a stranded cost filing pursuant to A.A.C R14-2-1607?
3) What costs should be included as part of stranded costs and how should those costs be calculated?
4) Should there be a limitation on the time frame over which stranded costs are calculated?
5) Should there be a limitation on the recovery time frame for stranded costs?
6) How and who should pay for stranded costs and who, if anyone, should be excluded from paying for stranded costs?
7) Should there be a true-up mechanism and, if so, how would it operate?
8) Should there be price caps or a rate freeze imposed as part of the development of a stranded cost recovery program and if so, how should it be calculated?
9) What factors should be considered for mitigation of stranded costs?

The First Amended Procedural Order of Docket No. U-0000-94-165 further ordered that Issue No. 3 of the Procedural Order include the following sub-issues:

3A) The recommended calculation methodology and assumptions made including any determination of the market clearing price.

3B) The implications of the Statement of Financial Accounting Standards No. 71 resulting from the recommended stranded cost calculation and recovery methodology.

The above issues are specifically addressed in Section 6 in this testimony on Stranded Cost Policy.

Q. HOW DID RUCO GENERALLY RESPOND TO THE STRANDED COST WORKING GROUP REPORT?

A. RUCO responded on September 25, 1997 with comments on procedure, general comments on stranded costs, and on the specific points raised by the stranded cost working group report, and offered responses to Staff's recommendation. Upon examining the Stranded Cost Working Group Report, RUCO decided that a more formal fact-finding process before the Commission was necessary before methods to follow in the electric restructuring process could be determined. RUCO contended that an informed policy-making process necessitated presentation of evidence from all interested parties, with opportunity for cross-examination of witnesses and rebuttal evidence.

Q. WHAT WERE RUCO'S GENERAL RESPONSES ON STRANDED COSTS?

A. Again, RUCO asserted that an evidentiary hearing was the appropriate forum for addressing the details pertaining to calculation methodology, computation, mitigation, and recovery of stranded costs. RUCO advocated consideration of fairness in the sharing of stranded costs, requesting that customers should not bear the total burden of stranded cost recovery. RUCO argued that utility investors must also assume some responsibility for stranded costs. RUCO also stated the importance of sharing a portion of stranded costs claimed by a utility as a financial incentive to mitigate such costs. Rate unbundling was mentioned by RUCO as the best means to identify the stranded cost component of electric rates. RUCO proposed that unbundling be carried out in a revenue-neutral manner, with each cost component being functionalized, classified and allocated as it is under current rate design.

Q. PLEASE SUMMARIZE RUCO'S RESPONSE TO THE SPECIFIC POINTS RAISED BY THE STRANDED COST WORKING GROUP REPORT.

A. RUCO responded to many specific recommendations addressed in the Report. In summarizing their responses, I will highlight major points of agreement and disagreement. RUCO generally agreed with the definition of stranded costs and the categories of costs included in stranded costs, although they emphasized the importance of taking into account the retailing expenses for generation in determining the retail price of generation services. RUCO agreed with the Staff report that the Rules should be changed to allow stranded cost recovery from customers who are on standard offer service, that stranded costs should be recovered from ratepayers using a charge with both an energy and demand component, and that tariffs for each rate class should continue to have the same billing determinants as they do now. RUCO also disagreed with the use of exit fees, clarified their position that a rate cap should be considered during the transition period only, not during the competitive period, and clarified that a revenue-neutral unbundling approach should be used, where rate design remains constant and is not updated to correct perceived flaws in the current rate design.

Q. DID RUCO RESPOND TO STAFF'S RECOMMENDATIONS?

A. RUCO responded on a point-by-point basis. Many of their responses have been incorporated into and restated in this testimony because I agree with those responses. Please refer to Section 6 on Stranded Cost Policy for details.

4. STRANDED COST METHODOLOGIES

A. Administrative Versus Market Valuation

Q. WHAT METHODOLOGIES ARE AVAILABLE TO ESTIMATE STRANDED GENERATION COSTS?

A. There are generally two methodologies for calculating stranded generation costs: *the market valuation approach* and *the administrative valuation approach*. The market valuation approach is when a utility's stranded costs are based on the differences between the *actual* auction, sale, or spin-off price of each of the utility's generation assets and the actual embedded cost of each of the utility's generation assets, net of generation-related Administrative and General (A&G) expenses. Under the administrative valuation approach, a utility's stranded generation costs would be based on the difference between *projections* of the utility's revenues for electric generation if generation prices were deregulated, and *projections* of the utility's revenues for electric generation if generation prices continued to be regulated based on the utility's current embedded costs of generation. RUCO supports the administrative valuation approach for calculating stranded generation costs.

Q. WHAT ROLE DOES UNBUNDLING PLAY IN EACH OF THE METHODOLOGIES DISCUSSED ABOVE?

A. Both of the methodologies discussed above require knowing the utility's total (i.e., economic and uneconomic) embedded cost of generation. This necessitates correctly *unbundling* the utility's embedded-costs-of-service from the utility's Cost-of-Service Study used to develop existing rates in its last base rate case. Electric service costs should first be unbundled into: 1) total generation and generation-related (i.e., competitive) ancillary services, 2) transmission and transmission-related (i.e., non-competitive) ancillary services, 3) distribution (including existing DSM), and 4)customer services.[1] Then, by using one of the methodologies discussed above, the *economic* generation and generation-related ancillary service costs would be separated from the *uneconomic* (i.e., stranded) generation and generation-related ancillary service costs.

Q. WITH RESPECT TO TEP, APS, AND SRP, WHAT NEEDS TO BE DONE IN ORDER TO ACCURATELY UNBUNDLE THE UTILITY'S COSTS OF PROVIDING EACH DISTINCT ELECTRIC SERVICE?

A. Rule 14-2-1606(C) ordered utilities, with the exception of SRP, file unbundled tariffs on December 31, 1997. These tariffs need to be evaluated. Utilities could have unbundled their current rates based on the Cost-of-Service Studies used in each utility's last base rate case. In this way, the rates for those services which are to remain regulated (i.e., transmission and distribution) will be fair and will not be recovering any costs that are attributable to services that may become unregulated (i.e., generation and aggregation). If APS, TEP and SRP developed new Cost-of-

[1] It will not be obvious how all of the costs, for example administrative and general ("A&G") costs, should be categorized. However, costs that pose this challenge should not merely be allocated to the transmission and distribution (i.e., regulated) categories because this might allow the utility's shareholders to avoid paying their share of some potentially stranded generation costs.

Service Studies and use these studies to unbundle their respective rates, then the issues of rate unbundling could be obscured by issues of rate redesign. This second approach would not produce an unbundling of current rates.

Q. PLEASE DESCRIBE THE MARKET VALUATION APPROACH IN MORE DETAIL.

A. In a perfect market, the sale price (which defines the market value) of each generation asset would reflect each buyer's estimates of the future costs and benefits of running the plant. Specifically, as described by Jonathan Lesser and Malcolm Ainspan:

> "the sale price [would] equal the buyer's expectation of the discounted[2] ... present value of the anticipated revenue stream less the present value of the future operating costs, plus the salvage value, if any."[3]

If an asset's market value is below its depreciated book value plus the present value of generation-related A&G expenses, then this difference is a stranded cost. If an asset's market value is above its depreciated book value plus

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[2] The market price of a generation asset would tend to reflect a private discount rate (the rate at which the value of money changes over time). Relative to regulated utility discount rates, private discount rates are higher. Higher discount rates would mean that the "value" of a generation asset to private investors in the market would be lower than the "value" of the asset to a utility and its ratepayers under regulation. Therefore, the switch away from regulation and its use of a regulated utility discount rate to a competitive market and its use of a private discount rate in itself creates some stranded generation costs.

[3] Lesser and Ainspan. "Using Markets to Value Stranded Costs." *The Electricity Journal*, October 1996; page 69.

A&G, then this difference is a negative stranded cost, which should be used to off-set the positive stranded costs associated with other assets.

Q. WHAT ARE THE ADVANTAGES OF THE MARKET VALUATION APPROACH?

A. The advantages of the market valuation approach are that: 1) the calculation of stranded costs would be relatively straightforward, 2) the calculation of stranded costs would be final, and 3) the divestiture of generation assets required by the approach might mitigate the potential exercise of vertical and horizontal market power in a deregulated generation market.

Q. WHAT ARE THE DISADVANTAGES OF THE MARKET VALUATION APPROACH?

A. The disadvantages of the market valuation approach are that: 1) the stranded costs would likely be significantly mis-estimated if the competitive generation asset market is undeveloped, 2) the divestiture of generation assets required by the approach might increase the potential exercise of horizontal market power in a deregulated generation market, 3) the approach can not easily accommodate a true-up mechanism to protect ratepayers from paying too much in stranded costs and utilities from recovering too little in stranded costs, 4) the stranded costs could be affected by the amount of the utility's assets (or a neighboring utility's assets) that are to be sold over a given period, as well as the timing of each sale, and 5) setting up the appropriate procedures for auctioning or spinning-off the generation assets would not be straightforward, nor would sorting out the federal and state tax implications.

Q. PLEASE DESCRIBE THE ADMINISTRATIVE VALUATION APPROACH IN MORE DETAIL.

A. Under the administrative valuation approach, stranded costs would be calculated as the net present value of the change in generation-specific revenues that a utility would experience over some specified time period as a result of selling electricity at market prices rather than at regulated prices. A utility's generation-specific revenue requirements would include the fixed and variable costs of generation, and some A&G expenses.

The administrative valuation approach could be used to calculate a utility's stranded costs regardless of whether or not divestiture of the utility's generation assets occurs on a voluntarily basis. In other words, a commission may believe that there are advantages to allowing a utility to divest its generation assets, but may also believe that until a competitive generation asset market develops, the asset sale prices should not be relied upon for the purposes of calculating stranded costs. Because asset sale prices could fluctuate significantly during the years when competition is developing, regulators may prefer to base the initial estimate of a utility's stranded costs on their *own* projections of market prices for generation. Furthermore, regulators could adjust (or "*true-up*") their initial stranded cost estimate annually to reflect actual market prices as they become known.

Q. WHAT ARE THE ADVANTAGES OF THE ADMINISTRATIVE VALUATION APPROACH?

A. The advantages of the administrative valuation approach are as follows: 1) The administrative evaluation approach could accommodate a true-up mechanism that would ensure ratepayers and utilities pay and recover their fair share of stranded costs, and would alleviate the need for exact projections of market prices for generation. 2) This approach would explicitly calculate stranded costs over a significant length of time (determined by the state regulatory commission). 3) This approach would allow a utility to divest some or all of its generation assets, but it would hold ratepayers harmless vis-à-vis the sale prices of any assets. 4) This approach would allow for distinguishing between the stranded costs themselves and the financing costs associated with them (i.e., the return on stranded investments) for the purpose of proposing a sharing mechanism.

Q. WHAT ARE THE DISADVANTAGES OF THE ADMINISTRATIVE VALUATION APPROACH WITH A TRUE-UP MECHANISM?

A. The disadvantages of the administrative valuation approach with a true-up mechanism are that: 1) the initial calculation and the annual true-ups of stranded costs would not be as easy and straightforward as the calculations under the market valuation approach, and 2) the true-up mechanism would still not entirely protect ratepayers from the negative price effects of an undeveloped competitive generation market and/or market power.

B. Description of Tellus Strandable Cost Model

Q. WHAT MODEL DID YOU USE TO CONDUCT YOUR ANALYSIS OF THE TEP, APS AND SRP STRANDED COSTS?

A. I used the Tellus Strandable Cost Model (SCM), which is based on the administrative valuation approach to valuing potentially stranded or uneconomic costs.

Q. PLEASE EXPLAIN BRIEFLY THE METHODOLOGY EMPLOYED IN THE STRANDABLE COST MODEL THAT YOU USED TO DEVELOP THE ESTIMATES.

A. The Tellus SCM is a simple spreadsheet model which performs three independent analyses: an unbundling analysis, a market price analysis for retail generation services, and projections of potentially strandable costs over a specified period of time. Using utility-specific data from the most recent FERC Form 1[4], the model develops an estimate of a utility's unbundled costs of generation, transmission, distribution and customer costs that are reflected in the utility's average retail rate. The unbundled cost of generation, or retail generation services, is then compared to a market price for retail generation services (RGS) in order to estimate potential stranded costs. In these analyses, I used 1996 as a base year, since APS' and TEP's most recently available FERC Form 1s were from December 31, 1996. I used 1996 financial data for SRP, as well. However, note that I have expressed all

[4] The FERC Form 1 is a mandatory filing regulated utility's must make to the Federal Energy Regulatory Commission under Federal Power Act, Sections 3, 4(a), 304 and 309 and 18 CFR 141.1.

my stranded cost results in 1998 present value dollars, not in 1996 present value dollars.

Q. DO YOU HAVE A DESCRIPTION OF THE TELLUS SCM?

A. Yes. A description of the Tellus SCM is provided in Exhibit (RAR-12).

Q. PLEASE DESCRIBE HOW YOU UNBUNDLED TEP'S , APS' AND SRP'S REVENUES.

A. I entered utility-specific costs and revenues using information provided in each utility's FERC Form 1 for 1996, or for SRP, a comparable source. The unbundled revenues were allocated to generation, transmission, distribution, and customer related expenses, based on a few simple allocation methods. Please see Exhibits (RAR-4) Table 2 (p. 3) for APS' rate unbundling results, (RAR-6) Table 2 (p. 3) for SRP's rate unbundling results, and , (RAR-8) Table 2 (p.3) for TEP's rate unbundling results.

Q. HOW WERE PLANT-RELATED COSTS ALLOCATED TO THE GENERATION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER COST COMPONENTS?

A. Ratebase or plant-related costs like depreciation and interest were allocated to each cost component based on that component's fractional contribution to net plant, e.g. generation-related net plant divided by total net plant was used to allocate these costs to the generation cost component.

Q. HOW ARE ADMINISTRATIVE AND GENERAL COSTS ALLOCATED TO THE GENERATION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER COST COMPONENTS?

A. Administrative and General costs are allocated to each functional cost component based on each component's fractional contribution to O&M less the sums of fuel and A&G expenses.

Q. ONCE THE TOTAL OPERATING REVENUES HAVE BEEN CALCULATED, ARE THERE ANY ADDITIONAL ADJUSTMENTS MADE PRIOR TO CALCULATING A PER KWH UNIT COST FOR EACH COST COMPONENT?

A. Yes. Wholesale Revenues are subtracted from Operating Revenues to calculate the Total Retail Revenues. It is the Total Retail Revenues for each cost component which are divided by Total Retail Sales to arrive at the unbundled per kWh cost for each cost component.

C. The Market Price of Retail Generation Services

Q. WOULD YOU BRIEFLY REVIEW THE CONCEPT OF "UNBUNDLING" AS IT RELATES TO THE CALCULATION OF STRANDED COSTS?

A. Again, unbundling refers to the process each utility must complete of dividing its current single or bundled rate into separate rates for customer services, transmission, distribution, and retail generation services. During this unbundling process, administrative and general costs (A&G) and various other common costs must be allocated fairly between these services. The resulting rates for transmission, distribution, and customer services would continue to be regulated by the ACC as monopoly services. However, the prices for retail generation services in Arizona will be competitive and set by the market beginning January 1, 1999. Thus, the difference between each utility's cost-based rate for retail generation services and the market price of retail generation is each utility's respective stranded cost for generation.

Q. WHAT TYPES OF COSTS WILL A COMPETITIVE SUPPLIER OF RETAIL GENERATION SERVICES LIKELY INCUR?

A. In addition to the cost of buying power at wholesale, the types of costs that a competitive supplier will incur to provide retail generation services fall into the following categories:

1. Generation-related customer services (e.g., billing, bill collection, responding to customer inquiries and complaints, arranging for new services or for switching services, etc.);

2. Ancillary services, such as load balancing and forecasting activities at the distribution circuit level needed to settle accounts with wholesale providers and to determine T&D charges and requirements, and risk management;

3. Marketing and advertising, including marketing incentives for new customers;

4. Generation-related administrative and general services, such as contracting for power, managing the aggregation company, providing office space to employees, etc.;

5. Profits and income taxes on profits; and

6. Other taxes.

Q. SHOULD EACH TYPE OF COST LISTED ABOVE BE INCLUDED IN THE MARKET PRICE FOR RETAIL GENERATION SERVICES USED TO COMPUTE STRANDED COSTS?

A. Yes, each type of cost listed above should be reflected in the estimated market price for retail generation services used to compute stranded costs. Each type of cost will be incurred by retail generation suppliers, regardless of whether they provide each and every service from in-house resources or whether they contract out certain services. Thus, projections of these retailing costs, which make up what I call the "retail margin," should be added to projections of competitive wholesale prices in order to derive a more accurate market price for retail generation services (an "RGS" market price) for computing stranded costs. Thus, it is the total market price for retail generation services as determined by alternative suppliers to the utilities that will determine the income that the existing utilities will be able to earn in the retail market.

Q. DID YOU EVALUATE THE LIKELY RETAIL MARGIN FOR APS, TEP AND SRP?

A. Yes, I did. The retail margin developed for each utility is a combination of A&G-related generation expenses developed in the unbundling process for each utility, and an estimate of the additional retail costs which would be incurred in order to sell generation services to customers within the State of Arizona.

Q. WHAT DID YOU ESTIMATE THE RETAIL MARGIN FOR APS, SRP, and TEP TO BE?

A. I estimated that a lower bound for the total retail margin would be about 0.77 cents per kWh in 1996 dollars. This is the sum of .50 cents per kWh for A&G related expenses, and a lower-bound estimate of additional retail services expenses of 0.27 cents per kWh. I have assumed that the retail margin would be the same for customers of all utilities within Arizona, since I have assumed the existence of a single state-wide retail market for generation.

Q. WHAT DOES THE CONCEPT OF RETAIL GENERATION SERVICES IMPLY FOR STRANDABLE COST CALCULATIONS?

A. The discussion above implies that the market price used to calculate costs that might become stranded due to retail competition must be the market price for retail generation services. Many parties have used wholesale market prices to calculate a utility's strandable costs, but by doing so, they have significantly over-estimated strandable costs.

In estimating ranges of the Affiliated Utilities' strandable costs, I have included the low retail adders appropriate for both small and large customers that I computed, and have weighted them across the 1996 sales of the small and large customer classes for the sum of APS' and TEP's retail sales in order to derive a low and a high value of the retail margin for the total load. Below, I will describe the full range of retailing costs that an efficient competitive supplier of retail generation services might incur in serving small and large customers. I will also provide estimates of the magnitude of each component of retail generation service cost. These estimates are summarized in Exhibit___(RAR-3), under the heading "Cost Components of a Retail Generation Services Adder."

Q. HAVE OTHER STATES ENDORSED THE CONCEPT OF MARKET PRICES OF RETAIL GENERATION SERVICES?

A. Yes, the New York State Public Service Commission, the New Hampshire Public Utilities Commission, and the Pennsylvania Public Utilities Commission have endorsed the concept of market prices of retail generation services for the purpose of establishing generation credits for pilot program participants.

In New York Case No. 96-E-0898, Rochester Gas and Electric identified thirteen "retailing functions" that would be the primary responsibility of the distribution company and fourteen retailing functions that would be the primary responsibility of the competitive supplier under retail competition. (See Exhibit___(RAR-11) for the list of retailing functions.) Furthermore, in New York Case No. 96-E-0948, the Commission established fixed adders to capture potential retailing generation costs and to encourage farms and food processors to participate in one of the state's retail pilot programs. The Commission set the retail adder at $4 per MWH for food processor participants (larger customers) and $10 per MWH for farm participants (smaller customers).[5]

In the New Hampshire pilot programs, the Public Utilities Commission approved a marketing cost credit of $3.70 per MWH for the state's 2-year pilot program for small customers. Finally, in Pennsylvania, the Commission concluded that for residential and commercial customers participating in the state's pilot programs, a retail generation credit of 3.0 cents per kWh should be adopted, along with a Customer Participation Credit ("CPC") of 13 percent of the difference between the current retail rate and the generation credit.[6]

Q. PLEASE BEGIN BY DISCUSSING EACH COST COMPONENT OF THE RETAIL MARGIN, IN PARTICULAR GENERATION-RELATED CUSTOMER SERVICE COSTS IN ORDER TO ILLUSTRATE HOW YOU DERIVED YOUR RESULTS IN EXHIBIT___(RAR-3).

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[5] The difference is explained by the New York Public Service Commission as follows: Actual retail access experience may show that avoidable retail and other expenses are greater for smaller customers on a unit (per kWh) basis, and it also appears that more of a per unit (kWh) discount will be necessary to encourage the participation of such smaller customers in the programs." (Case 96-E-0948 - Order Establishing Retail Access Pilot Programs, page 7).

[6] Docket Nos. P-00971168, P-00971169, P-00971170, P-00971171, P-00971172, P-00971173, P-00971175, and P-00971183. Motion of Chairman John M. Quain at 3 (August 21, 1997).

A. A key generation-related customer service cost is the cost of billing customers for retail generation services and collecting bill payments. Under retail generation services, there will also be customer calls to handle, including requests for information, requests for service, and complaints. Thus, generation-related customer service costs will at least include: 1) billing and collection service costs, and 2) costs to have customer service representatives available to answer telephone inquiries and requests from customers. Competitive alternative suppliers may do their own billing, they may pay the distribution company to do their billing for them, or they may pay a third party to do their billing. If they do their own billing, they will need to invest in computer systems to perform the task. If they pay the distribution company to do their billing, they should pay whatever the incremental cost is to the utility to perform this task. If they contract with a private billing company, they will pay according to their contract with that company.

Q. WHAT IS YOUR ESTIMATED RANGE FOR GENERATION-RELATED CUSTOMER SERVICE COSTS?

A. My estimates of generation-related customer service costs range from a low of \$1.00 per month per customer to a high of \$2.00 per month per customer, or about \$1.10 per MWH to \$2.20 per MWH, for small customers such as those served by APS and TEP, who together use an average of 917 kWh per month. My estimate of generation-related customer service costs is about \$0.50 per MWH for large customers in the low case and about \$1.00 per MWH in the high case.

My estimates are based, in part, on claims made by utilities in other states. As part of its pilot proposal, Pennsylvania Power & Light (PP&L) proposed a fee of $1.50 per bill for Billing and Collection Service, even though it claimed that its true cost would be $2.05.[7] Similarly, PECO Energy Company proposed a fee of $0.90 per bill.[8] It is important to note that so far, there is no evidence that the utilities' proposed fees reflect the true *incremental* costs that they would incur. Nonetheless, these proposed fees provide a conservative range of prices for *all* generation-related customer services, since my proposed ranges do not include any costs that a supplier would incur to install a billing and collection system or to answer customers' telephone inquiries and requests, outside of billing-related calls.

Q. PLEASE DISCUSS THE COSTS OF ANCILLARY GENERATION-RELATED SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888.

A. There are likely to be additional generation-related ancillary services that were not identified in FERC Order No. 888. As I mentioned earlier, in New York Case No. 96-E-0898, Rochester Gas and Electric has identified twenty seven "retailing functions" that would be the responsibility of the distribution company and/or the competitive supplier. (Refer to Exhibit___(RAR-11) for the list of other potential ancillary services.) Of these twenty seven functions, ones such as "forecasting of customer energy requirements" and "scheduling of capacity and energy purchases

[7] Docket No. P-00971183, PP&L's Comments at 40 (May 22, 1997).

[8] Docket No. P-00971170, PECO's initial petition.

and delivery to the service area" could all be classified as additional generation-related ancillary services. These services will be either partially or fully the responsibility of alternative suppliers, depending on the responsibilities of the Independent System Operator (ISO).

Q. WHAT IS YOUR ESTIMATED RANGE FOR THE COSTS OF ANCILLARY SERVICES OTHER THAN THOSE THAT WILL BE PROVIDED UNDER TRANSMISSION TARIFFS REQUIRED BY FERC ORDER NO. 888?

A. In order to be conservative, my estimate of ancillary services other than those identified in FERC Order No. 888 ranges from $0 per MWH to $1.00 per MWH for both small and large customers under the low and high cases.

Q. PLEASE DISCUSS GENERATION-RELATED A&G COSTS.

A. All vertically-integrated utilities have incurred, and competitive alternative suppliers will continue to incur, generation-related A&G costs. These costs include those for corporate headquarters, salaries for top management, office supplies and services, administrative support, etc. Thus, when utilities properly unbundle their rates, they should allocate generation-related A&G to the generation component of rates. Furthermore, economic generation-related A&G should be moved to the utilities' own unregulated aggregation affiliates, if such affiliates are established as the sale of retail generation services become deregulated. This important aspect of unbundling has already been supported by some Pennsylvania utilities. For example, in the Code of Conduct proposed by

Pennsylvania Electric Company and Metropolitan Edison Company, the companies stated that "the LDC shall fairly allocate to its Affiliate costs for general administration or support services, ... so as not to give the LDC or its Affiliate an unfair advantage over competitors through an allocation of these costs."[9] This policy of fairly allocating generation-related A&G costs as the sales of retail generation services shift from the regulated utility to the unregulated subsidiary of the utility should be followed by all utilities, regardless of whether they only functionally unbundle, or whether they fully divest their generation function.

Q. WHAT IS YOUR ESTIMATE OF GENERATION-RELATED A&G COSTS FOR ALTERNATIVE SUPPLIERS?

A. My estimate of generation-related A&G costs is $5.00 per MWH for small and large customers in both low and high cases. This figure is based on APS' relatively low generation-related A&G costs, which I arrived at by allocating 71 percent of the utility's total A&G costs in 1996 to its generation function. The generation-related A&G value for SRP is almost identical. This figure is about 94 percent of my estimate of the 1994 national average generation-related A&G cost for investor-owned utilities (not corrected for inflation).[10] Therefore, I have made the assumption that efficient alternative suppliers could provide generation-related A&G at about the same cost as APS and SRP, since alternative suppliers will likely

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9 Companies' respective initial pilot proposal filings at 31.

10 The 1994 national average generation-related A&G component is approximately $5.30 per MWH and the national average bundled retail rate is $71.60 per MWH for investor-owned utilities.

try to keep their generation-related A&G costs to a minimum and APS and SRP appears to be fairly efficient as far as their generation-related A&G costs are concerned.

Q. PLEASE DISCUSS MARKETING AND ADVERTISING COSTS.

A. Competitive alternative suppliers will incur significant costs for marketing and advertising, which are costs that regulated vertically integrated utilities have not had to incur because their customers have been captive. (Sometimes the utilities have incurred these costs on a voluntary basis.) Alternative suppliers will have to incur large marketing costs initially to gain market share. They will have to make significant investments in marketing and advertising to foster good customer relations and to try to convince retail customers (especially smaller consumers) to switch from the existing service provider they know (and to which they may be loyal) to one they do not know.

Q. WHAT IS YOUR ESTIMATE OF MARKETING AND ADVERTISING COSTS?

A. My estimate of marketing and advertising costs ranges from a low of $1.00 per MWH to a high of $2.00 per MWH for small customers, and a low of $0.50 per MWH to a high of $1.00 per MWH for large customers. My estimated range derives, in part, from the New Hampshire pilot programs. There, the Public Utilities Commission approved a marketing cost credit of $3.70 per MWH for the state's 2-year pilot programs for small customers. The N.H. PUC arrived at this estimate by assuming that a competitive supplier participating in a 24 month pilot program would spend $44 on a customer who consumes an average of 500 kWh per month. Many alternative suppliers in the N.H. pilots offered to give each residential pilot participant approximately $25 as a "signing bonus" or roughly the equivalent in conservation measures and gifts. It is reasonable to assume that these suppliers will spend an additional $19 or more per customer over 2 years on other forms of marketing and advertising, such as telemarketing, multi-media advertising, and the like.

If suppliers in Arizona spend $44 in marketing and advertising over a 2-year period on small customers who consume an average of 917 kWh per month, then that it is equivalent to spending about $2.20 per MWH for small customers. Even if suppliers spend as little as $24 per customer on marketing and advertising, this is equivalent to spending about $1.10 per MWH on a customer who consumes 917 ,000 kWh per month for 24 months. I am assuming that the average customer may switch suppliers or need to be offered an incentive to stay with his/her existing supplier every 2 years or so. On a per MWH basis, marketers are likely to spend even less than this on large customers. This is why I chose the conservative range of $0.50 per MWH to $1.00 per MWH for large customers.

Q. ARE THERE ANY OTHER COST COMPONENTS THAT ALTERNATIVE SUPPLIERS WILL HAVE TO COLLECT FROM RETAIL RATEPAYERS IN THE LONG RUN?

A. Yes. If alternative suppliers want to stay in business during the mid- to long-term under retail competition, they will need to earn a profit margin on more than just their capital investment in generation, if they have any such investments. (Some alternative suppliers may purchase all their power from others.) Once they earn this profit margin, they will need to pay federal and state income taxes on it. Therefore, in the longer run, alternative suppliers will need to recover these types of costs through the prices they charge for retail generation services.

I have assumed a profit margin of 10 percent on the four above-mentioned components of the retail adder, and an income tax rate of 35 percent of the profit margin.

Q. PLEASE SUMMARIZE WHAT YOUR PROPOSED LOW AND HIGH RETAIL ADDERS ARE FOR SMALL AND LARGE CUSTOMERS.

A. Once the costs of the above components are added together, my proposed retail adder for small customers ranges from a low of $8.20 per MWH to a high of $11.80 per MWH. My proposed retail adder for large customers ranges from a low of $6.40 per MWH to a high of $8.50 per MWH. I then took a weighted average of the low and high estimates based the sum of APS' and TEP's 1996 retail sales by customer class that were cited in their 1996 FERC Form #1 data. Thus, my estimated retail adder, averaged across small and large customer classes, ranges from a low of 0.77 cents per kWh to a high of 1.1 cents per kWh. For my analysis of stranded costs I only utilized the low case value of 0.77 cents per kWh.

D. Unbundling Results for APS, SRP and TEP

Q. DID YOU USE THE TELLUS UNBUNDLIGN METHODOLOGY TO DEVELOP ESTIMATES OF THE UNBUNDLED REVENUES FOR APS, TEP, AND SRP?

A. Yes, I did.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR APS?

A. The unit unbundled revenues for APS were as follows:

- Generation - 5.02 cents per kWh
- Transmission - 0.59 cents per kWh
- Distribution - 2.06 cents per kWh
- Customer - 0.38 cents per kWh.

The total average retail rate was 8.05 cents per kWh.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR TEP?

A. The unit unbundled revenues for TEP were as follows:

- Generation - 6.12 cents per kWh
- Transmission - 0.83 cents per kWh
- Distribution - 1.32 cents per kWh
- Customer - 0.29 cents per kWh.

The total average retail rate was 8.55 cents per kWh.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR SRP?

A. The unit unbundled revenues for SRP were as follows:

- Generation - 4.85 cents per kWh
- Transmission - 0.38 cents per kWh
- Distribution - 1.02 cents per kWh
- Customer - 0.27 cents per kWh.

The total average retail rate was 6.52 cents per kWh.

E. The Wholesale Market Price Projection

Q. PLEASE DESCRIBE THE METHODOLOGY YOU USED TO PROJECT WHOLESALE ELECTRICITY PRICE.

A. The major assumption underlying my methodology is that the future average annual wholesale market price of electricity could be approximated by the average unit cost of supplying energy and capacity to meet utility's incremental load in each year using only state-of-the-art new Combustion Turbine (CT) and Combined Cycle (CC) power plants. These two types of power plants were chosen because they are well-known to be the lowest cost new technologies to meet peaking and baseload type demand, respectively.

Q. PLEASE EXPLAIN WHY THIS PROJECTED AVERAGE UNIT COST FOR MEETING INCREMENTAL LOADS YIELDS A REASONABLE ESTIMATE OF THE AVERAGE ANNUAL WHOLESALE PRICE OF ELECTRICITY.

A. First of all, it is important to point out that this methodology does **not** intend to provide a precise prediction of the wholesale market price of electricity that may evolve in a deregulated power market. Instead, it attempts to estimate a **lower** bound for such prices.

The exact market price of electricity will depend on the actual structure of electricity market that is yet to evolve in Arizona. However, regardless of such a structure, at some point in the future the existing generation capacity will become insufficient to meet growing demand and new generation capacity must be built. In a competitive deregulated environment, a new market entry will occur only if the market price of electricity is high enough to compensate project developers for costs incurred to finance, construct, and operate new power plants. Thus, the wholesale market price for power to meet a certain type of load (e.g., peaking, cycling, baseload) should be no less than the unit cost of financing, constructing, and operating those plants needed to meet that load in the least-cost way.

Q. HOW DID YOU ESTIMATE THE UNIT COST OF FINANCING, CONSTRUCTING, AND OPERATING INCREMENTAL GENERATION CAPACITY REQUIRED TO MEET INCREMENTAL LOAD FOR EACH UTILITY FOR WHICH YOU COMPUTED STRANDABLE COST?

A. I considered the two generation technologies -- state-of-the-art new gas fired Combustion Turbines (CT) and Combined Cycle (CC) power plants and calculated the least cost mix of these technologies required to meet the 1996 load profile of each utility.

Q. WHY DID YOU CALCULATE THE MIX REQUIRED TO MEET THE ENTIRE SYSTEM LOAD AS OPPOSED TO CALCULATING THE MIX REQUIRED TO MEET AN INCREMENTAL LOAD?

A. It is important to note that the unit cost of power does not depend on the magnitude of the incremental load, but on its shape. If the shape of utility's incremental load is the same as the shape of its total system load in 1996, the resulting unit cost of generation found for the system load would be the same as for the incremental load. In other words, calculating a unit cost of serving an entire system load is just a method of computing a unit cost of serving an incremental load that has the same load characteristics.

Q. WHAT WERE YOUR INPUT ASSUMPTIONS REGARDING THE COST AND HEAT RATES OF CT AND CC POWER PLANTS?

A. I used the most recent available information regarding the cost and heat rates of CC and CT plants. The CC data I used was as follows: capital cost of $383 per kW, fixed O&M cost of $11.7 per kW-year, variable O&M cost of 0.2 mills per kWh, and heat rate of 6,500 Btu per kWh. I used CT data developed by Tellus Institute for use in *Energy Innovations - A Prosperous Path to a Clean Environment* (June 1997). The CT data were as follows: capital cost of $275 per kW, fixed O&M cost of $9.4 per kW year, variable O&M cost of 0.1 mills per kW, and heat rate of 11,900 Btu per kWh.

Q. WHAT FIXED CHARGE FACTOR DID YOU USE TO ACCOUNT FOR CAPACITY COSTS ON AN PER KWH BASIS?

A. I used a real levelized fixed charge factor of 10.88 percent. This fixed charge factor assumes a 20-year financing period at a private rate of 10.5 percent which is intended to be for projects developed without regulatory guarantee for cost recovery.

Q. HOW DID YOU ESTIMATE THE AVERAGE "BUS BAR" COST OF THE OPTIMAL CC/CT MIX?

A. To determine the likely future mix of CCs and CTs for a utility's system, the methodology I used conducts a "crossover calculation" to determine the capacity factor below which CTs will operate at least-cost and above which CCs will operate at least cost. The outcome of the crossover calculation is a key input to determine the combination of CCs and CTs which would serve this utility's system at the lowest cost, based on the load profile of the utility in the base year.

Q. WHAT ASSUMPTION DID YOU MAKE REGARDING THE TIMING WHEN THE NEW CAPACITY WILL BE NEEDED IN ARIZONA?

A. For the purpose of these calculations, I assumed that the new capacity will be needed in 2000. In other words, I assumed that from 2000 and onward, the market price of electricity in Arizona will be equal the unit cost of an optimal mix of new capacity.

Q. WHY HAVE YOU ASSUMED THAT THERE WILL BE A NEED TO ADD NEW CAPACITY TO EACH UTILITY'S SYSTEM IN THE YEAR 2000?

A. My assumption is based on the long-term forecast of the electric utility industry development in the Western Systems Coordinating Council/RA (Region 12) region prepared by Energy Information Administration (EIA). In its 1997 Annual Energy Outlook (AEO-97), EIA shows unplanned additions of CC and CT units of relatively small magnitude (about 120 MW of new CC capacity and 180 MW of new CT capacity) in that region starting in 1996. EIA projects further annual additions of new CC and CT capacity such that between 1996 and 2000, approximately 1500 MW of new CC capacity and 880 MW of new CT capacity will be added to the RA system. It is important to note that year 2000 is the first year in which only CC capacity is added to the system and no CT capacity. This indicates that effective in the year 2000, the regional electricity market will need mostly additional baseload capacity and no peaking capacity. Therefore, it is safe to assume that starting this year almost **all** incremental load has to be served by newly added capacity. This assumption justifies the reliance on unit cost of an optimal CC/CT mix as a lower bound for the market price in the year 2000.

Q. DID YOU RELY ON THIS METHODOLOGY IN DEVELOPING MARKET PRICE PROJECTIONS FROM 2000 ONWARD FOR ALL UTILITIES IN ARIZONA?

A. Yes, I basically used this methodology for all three utilities, with one minor exception. I used this methodology for developing market price projections for two companies – APS and TEP. However, I did not have all the necessary load data for SRP. Therefore, for the purpose of estimating SRP's stranded costs, I assumed that in each year from 2000 onward its projected market price be equal to the average of market price projections for APS and TEP. Since these two market price projections were almost the same, this ought to be a good approximation for SRP.

Q. WHAT ASSUMPTION DID YOU MAKE REGARDING THE MARKET PRICE OF ELECTRICITY BETWEEN 1996 AND 2000?

A. I assumed that in 1996 the wholesale market price of electricity would be equal to the average price of purchased power paid by each utility in that year. This is an assumption that tends to overestimate stranded costs because the bulk of these power purchases are non-firm and this average price substantially underestimates the price of wholesale power which might have been observed if the electricity market became fully deregulated and competitive in Arizona in 1996. My estimated market price in the 3 years between 1996 and 2000 is based on a simple interpolation of the estimated price for 1996 and the CC/CT based price in 2000.

Q. WHAT ASSUMPTIONS AND DATA SOURCES DID YOU USE TO PROJECT THE UNIT COSTS OF NATURAL GAS AT WHICH IT WILL BE AVAILABLE AS A FUEL FOR NEW CT AND CC PLANTS?

A. I developed a forecast of appropriate natural gas prices in two steps. <u>First</u>, I started with a forecast price of natural gas for power generation in the Mountain

Region of the U.S. developed by EIA in AEO-97. Second, I increased this forecast by factor of 12 percent to reflect the fact that historical prices of natural gas use for power generation in Arizona were on average 12 percent higher than similar prices in the entire Mountain Region in recent years, as shown in Exhibit RAR-10.

Q. DID YOU MAKE ANY FURTHER ADJUSTMENTS TO THIS ESTIMATED WHOLESALE MARKET PRICE OF ELECTRICITY?

A. Yes, I included two adders to reflect: 1) FERC Order 888 ancillary services worth 1 mill per kWh, and 2) a transmission and distribution line loss adder appropriate for each company.

Q. HOW DID YOU OBTAIN THE BASE YEAR MARKET PRICE FOR RETAIL GENERATION SERVICES THAT YOU USED IN THE PROJECTIONS OF EACH COMPANY'S POTENTIAL STRANDED COSTS?

A. To obtain the base year market price for retail generation services that I used in the projections of the Company's potential stranded costs, I added to the total wholesale price a retail margin of 0.77 mills per kWh which I discuss in Section 4.B of this testimony.

Q. WHERE IN YOUR TESTIMONY COULD YOUR MARKET PRICE CALCULATIONS BE FOUND?

A. Market price calculations for the Arizona Public Service Company and for Tucson Electric Power are presented on pages 4-6 of Exhibit RAR-4 and Exhibit RAR-8, respectively. Market price calculations for SRP are presented on pages 4 and 5 of Exhibit RAR-6.

Q. DID YOU DEVELOP ANY ALTERNATIVE PROJECTIONS OF THE RETAIL MARKET PRICE FOR THE PURPOSE OF COMPUTING STRANDABLE COSTS?

A. Yes. In addition to the forecast described above (Base Case Scenario), I developed two alternative market price projections for each Company – a High Market Price Scenario and a Low Market Price Scenario. Under the High Market Price Scenario, I simply increased the projected market price by 5 percent in each year from 2000 onward. Similarly, under the Low Market Price Scenario, I reduced the projected market price by 5 percent in each year from 2000 onward. In both cases I used the same starting point for the retail market price in 1996, and I interpolated between the 1996 price and the year 2000 price in both the High and Low Market Price Scenarios.

F. Projections of Regulated Generation Rates

Q. HOW DID YOU FORECAST THE UNBUNDLED GENERATION SERVICE RATE UNDER THE ASSUMPTION THAT CURRENT REGULATION CONTINUED FOR EACH COMPANY BEYOND 1996?

A. For the purpose of my analysis of stranded costs, I simply assumed that the unbundled generation service rate would stay constant in nominal dollars over the

25-year period 1996-2020 for TEP and SRP. By assuming that this unbundled rate would remain constant, I am implicitly assuming a trade-off that would impact revenue requirements between increasing fuel and O&M costs over time, and depreciating generating assets. This assumption also reflects the fact that the market price for purchased power will likely be lower than embedded generation costs for several years into the future, but will then begin to increase. In order to improve on this assumption, I would need to utilize long-run financial forecasts of each utility, which were not available to me.

For APS I assumed that, beginning in year 2004, the regulated generation rate will increase at 1.0 percent per year, after remaining constant from 1998-2003. This increase was assumed to result from the end of the rapid depreciation of most of the Company's regulatory assets.

Q. WHAT ASSUMPTIONS DID YOU MAKE TO FORECAST SALES VOLUMES OF EACH COMPANY BEYOND 1996?

A. I escalated each of APS' and TEP's base year sales volumes at an annual rate which reflected that Basecase sales forecast in their 1995 IRP filings. For SRP I used their actual growth rate in sales for 1985-1995.

5. STRANDED COSTS RESULTS

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ESTIMATES OF POTENTIAL STRANDED COSTS FOR THE THREE UTILITIES.

A. I present the summary results of my stranded cost analyses in Exhibit RAR-2. As shown in this exhibit, the potential net present value of stranded costs in 1998 dollars vary substantially with market price scenario, and with the time frame over which estimates are made. This is a typical result. However, it is important to note that potential stranded costs for APS and for SRP are consistently negative in all scenarios over the time frame 1998-2020; whereas strandable costs for TEP are positive in the period 1998-2020 in all scenarios. The time period 1996-2020 is sufficiently long to represent a reasonable period over which to compute stranded costs, since most if not all generation assets will last this long. A similar pattern could be observed over a shorter, 15-year period of time, 1998-2012, with one exception – positive stranded costs for APS result in the low market price scenario, and slightly positive stranded costs result for APS in the Basecase. Thus, TEP's stranded costs are also positive if the calculation is made over the 15-year period from 1998-2012. However, the 15-year period 1998-2012 is such a short time period over which to measure strandable costs that the small positive value of $102 million (PV) for APS in the Basecase should not be taken as significant when compared to the strongly negative $838 million (PV) result obtained if the calculation is continued through 2020.

In short, these results lead to a conclusion that the deregulation of electricity market will likely create no materially significant strandable costs for APS or SRP. However, TEP will likely have a significant level of strandable costs.

Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED COSTS COMPUTED OVER THE 15-YEAR PERIOD 1996 THROUGH 2010.

A. I made these calculations mostly for illustrative purposes only. The period 1996-2010 is not an appropriate time period over which to compute stranded costs. Indeed, this period covers two past years, 1996 and 1997. The results show that ratepayers have already paid for about $556 million, $456 million, and $434 million in strandable or uneconomic costs for APS, TEP, and SRP, respectively, in just those two years. I simply wanted to include these two years in my analysis because available base year data start in 1996. Furthermore, as I stated earlier, my market price estimates in these two years are likely to substantially understate the price of power which would have been observed if electricity market became fully deregulated and competitive in Arizona in 1996. This is especially true for TEP which was buying power primarily on a non-firm basis at a low price of 1.59 cents per kWh. Finally, by beginning my analysis in 1996, one can see how fast ratepayers are paying for uneconomic generation costs during 1996 and 1997 when compared with the overall long-term magnitude of these strandable costs. (See page 1 of Exhibits RAR-4, RAR-6, and RAR-8.

Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED COSTS COMPUTED OVER THE 15-YEAR PERIOD 1998 THROUGH 2012.

A. Again, I believe that these results provide an **upper limit** on the potential stranded costs for each company for each market price scenario. Certainly, a shorter time period should not be relied on for the purpose of setting a stranded cost recovery charge. For example, APS' strandable costs in the period 1998-2012 range from negative $417 *million* under the High Market Price Scenario to positive $559 million under the Low Market Price Scenario. Thus, strandable costs for APS roughly center around zero even when computed over this relatively short time period.

Q. PLEASE DISCUSS YOUR ESTIMATES OF POTENTIAL STRANDED COSTS COMPUTED OVER THE PERIOD 1998 THROUGH 2020 WHEN COMPARED WITH THOSE COMPUTED OVER THE PERIOD 1998 THROUGH 2012.

A. The results for 1998-2020 illustrate that the potential stranded costs decrease significantly with further extension of the period used for the stranded cost calculations. This result simply reflects the fact that the farther out one goes in time, the higher retail market prices are likely to be with respect to projected regulated prices for generation.

Q. WHICH EXHIBITS SUPPORT THE DEVELOPMENT OF THESE STRANDABLE COST ESTIMATES?

A. Exhibits RAR-4 and RAR-5 support my results for APS; Exhibits RAR-6, and RAR-7 support results for SRP, and Exhibits RAR-8 and RAR-9 support results for TEP. As these exhibits differ only with respect to specific utility data and to the +/- 5 percent adjustment to market price of generation assumed for the stranded cost calculation, it will suffice to focus only on Exhibit RAR-4 here in order to explain all six exhibits.

Q. PLEASE TURN TO AN EXAMINATION OF EXHIBIT (RAR-4).

A. In Table 1, Exhibit RAR-4 page 4, I present a calculation approximating the least-cost price of supplying energy to meet APS' customer demands using the mix of new CC and CT power plants, as I explained earlier. The result is a wholesale market price of 3.31 cents per kWh in 1996 dollars, and a retail market price of 4.08 cents per kWh.

In Table 2, Exhibit RAR-4 page 3, I present a summary of the calculation of the unbundled cost of generation, transmission, distribution, and customer-related services based on APS' 1996 costs. The 1996 unbundled price of generation was calculated to be 5.02 cents per kWh under current regulation. This unbundled generation price becomes the baseline generation price against which the retail market price is compared to evaluate potential stranded costs. Again, as I stated earlier, in making our projections I assumed that the generation component of current rates would remain constant in nominal terms for 8 years, and then would increase at 1.0 percent per year.

In Tables 3a and 3b, Exhibit RAR-4, pages 2 and 1, respectively, I present the yearly calculation of potential stranded costs for APS. The differences between the market price and generation price listed in Table 3a become an input to Table 3b. In Table 3b, the price differences represent the per-kWh strandable costs. These unit strandable costs are multiplied by the forecasted retail Arizona jurisdictional sales for each year to determine an annual strandable cost estimate. These yearly strandable cost estimates are summed, and the net present value (in 1998 dollars) of three streams of retail strandable costs is determined, one for a 15-year period 1996-2010, another for a 15-year period 1998-2012, and a third one for a 23 year period, 1998-2020.

A final step in calculating the projected strandable costs that are computed *externally* to the SCM, is to add the net present value of generation-related regulatory assets not currently in rate base to the estimate of projected strandable costs already in rates. My initial estimate of the present value of these regulatory assets for APS is about $110.3 million.

Table 4, Exhibit RAR-4, page 5, and page 6 of Exhibit RAR-4 presents a summary of many of the assumptions made in modeling APS' estimated strandable costs. This provides a complete overview of all key financial and modeling assumptions, and is simply for reference purposes. No calculations are presented in this table.

Q. PLEASE COMMENT ON THE FACT THAT YOUR ESTIMATES OF STRANDED COSTS ARE QUITE SENSITIVE TO THE MARKET PRICE PROJECTION UNDERLYING EACH SCENARIO.

A. It is important to note that my results for strandable costs are preliminary estimates that can and should be refined based on a more detailed accounting analysis of all three companies' unbundled rates, regulatory assets, and more accurate forecasting of future unbundled generation rates under regulation. Assuming that a true-up procedure is adopted for the recovery of stranded costs, the current uncertainty in market prices will not matter significantly, since the actual stranded costs collected from ratepayers, if any, can be adjusted when actual retail market prices for generation become known in the future. Thus, the Commission and other stakeholders should focus their attention next on the most accurate unbundling of utility rates possible in order to derive the most accurate possible projection of each company's generation costs under regulation. As part of the unbundling process, the Commission should make sure that all past costs including A&G expenses, that were caused by the construction or operation of generation facilities, or the contracting for purchased power, are allocated to the generation component of rates, and are removed from transmission and distribution rates.

Q. WHAT IS YOUR MAJOR CONCLUSION BASED ON THE RESULTS OF THESE ANALYSES?

A. Again, the major conclusion of my determination of stranded costs is that the deregulation of the electricity market will create no materially significant amount of positive strandable costs in Arizona, except for TEP. This implies that, if retail competition is initiated in Arizona, there may need to be a **negative** stranded cost recovery charge put into place for APS and SRP in order to prevent their ratepayers from paying more for electric generation over the next 10-15 years than they would have if the regulation of generation prices had continued during this time. Even if the stranded cost recovery charge is negative, the same basic policies can be followed as recommended in Section 6 below. In particular, a negative stranded cost recovery charge still needs to be trued-up periodically in order to ensure that ratepayers do not pay more than they would under continued regulation of generation prices. One reason why the stranded costs of APS and SRP are so strongly negative from 1998 forward is that ratepayers have already (or will have soon) paid the uneconomic costs embedded in each utility's generation mix in the past. This is typical since the costs of most uneconomic power plant investments are front-loaded in the early years due to utility accounting practices. Once ratepayers have paid for the uneconomic costs of these power plants, it would be unfortunate if they do not get the longer-run benefits of these plants when the cost of their output is lower than market priced alternatives.

6. STRANDED COST POLICY

Q. WOULD YOU PLEASE RESPOND TO EACH OF THE NINE QUESTIONS OR ISSUES THAT THE ACC NOTED IN ITS DECEMBER 2, 1997 ORDER?

A. Yes, I will now proceed to address each issue raised by the ACC in light of RUCO's previous September 25, 1997 response to the Stranded Cost Working Group Report. The questions have been responded to in order of importance.

Issue No. 2

Q. WHEN SHOULD 'AFFECTED UTILITIES' BE REQUIRED TO MAKE A STRANDED COSTS FILING PURSUANT TO A.A.C. R 14-2-1607?

A. The stranded cost filing should occur as soon as possible, or at least nine months before the beginning of implementation of retail competition. Section R14-2-1604 details the phases to retail access over four years- beginning on January 1, 1999 and completing phase-in on January 1, 2003. Thus, I recommend that to be consistent with Section R14-2-1604, all stranded cost filings should be made by April 1, 1998. Customers should also see their rates unbundled on their bills at least two months before January 1, 1999, once the ACC has finalized its decision as to the appropriate stranded cost recovery charge for each utility.

Issue No. 3.A

Q. WHAT IS YOUR RECOMMENDED CALCULATION METHODOLOGY AND WHAT ASSUMPTIONS SHOULD BE MADE IN DETERMINING THE MARKET CLEARING PRICE?

A. Stranded costs should be defined as the difference between the competitive market value of retail generation services and the embedded cost of a utility's generation assets. Therefore, the stranded costs for all Affected Utilities including SRP should be calculated using the administrative valuation approach unless a sale of the assets actually occurs. This approach compares projections of the utility's revenues for electric generation if generation prices were deregulated, and projections of the utility's revenues for electric generation if generation prices were continued to be regulated based on the utility's embedded costs of generation. The difference between these two reference streams would, then, be the revenues "lost" if retail access were implemented. This difference should also be present valued. The result is an estimate of net stranded costs across all generation resources.

The administrative valuation approach leads to knowing what the utility's total economic and uneconomic embedded cost of generation is and, therefore, helps to determine the correct unbundling of the utility's current embedded cost-of-service. Electric service costs should initially be unbundled into total generation-related ancillary services, transmission and transmission-related ancillary services, distribution, and customer services (such as metering and billing). Through use of the administrative valuation approach, the economic generation and generation-related ancillary service costs would also be separated from the uneconomic or stranded generation costs.

Q. SHOULD THE "STRANDED COST" METHODOLOGY COMPUTE UNECONOMIC COSTS THAT ARE ACTUALLY STRANDED BY THE ONSET OF RETAIL COMPETITION, OR SHOULD THE METHODOLOGY YIELD THE TOTAL FOR ALL STRANDABLE OR UNECONOMIC COSTS AS OF A SPECIFIC DATE?

A. I believe the calculation methodology should yield total *potentially* stranded or strandable costs as of a specific date, not just costs actually stranded due to customers leaving the utility's system for an alternative supplier. As indicated above, this assumes that the utility would be forced to charge customers a retail market price for all of their generation in a fully competitive market, regardless of what its embedded generation costs are. As discussed above, the stranded cost calculation methodology must focus on the retail price of electricity and not just the wholesale market price which would be just one component of a retail price. After all, once unbundled correctly, the generation component of current rates is the retail price that customers are paying for generation services. Thus, the market price that this generation-related revenues stream is being compared to must also be a retail price for generation services, not a wholesale price.

Q. HOW SHOULD THE MARKET PRICE OF POWER BE DETERMINED?

A. The estimation of a retail market price should explicitly be based on the assumption that in a competitive retail market, the Affiliated Utilities would likely charge all customers this market price for generation services. The average market price represents the energy and demand costs necessary to serve the utility's entire load. Therefore, the retail market price represents the average retail cost of power in the region to serve a particular load based on its load factor and other seasonal characteristics, as opposed to just the marginal wholesale cost in the market at certain time-periods. A reasonably accurate wholesale market clearing price should rely on cost information for a new natural gas combustion turbine and a new natural gas combined cycle plant to determine a market price based on the optimal mix of CTs and CCs to serve a particular utility's entire load profile. Using the cost of CCs and CTs to calculate the market price is likely to represent a "low case" market price value, since it is unlikely that the wholesale market price for generation would be less than the cost of new CCs and CTs. This issue was discussed further in Section 4.B. of this testimony.

In developing estimates of the retail market price for power, taking into account only the wholesale price of power is insufficient, as noted above. The correct valuation should be based on retail prices for generation services to the customer, which are equal to wholesale prices plus a retail margin. In order to provide retail generation services to end-use customers, alternative suppliers will have to incur many costs not embedded in market prices of bulk or wholesale power, such as administrative and general expenses, billing service costs, customer service costs, marketing and other transaction costs, as discussed above.[11]

Issue No. 3

Q. WHAT COSTS SHOULD BE INCLUDED AS PART OF 'STRANDED COSTS' AND HOW SHOULD THOSE COSTS BE CALCULATED?

A. As discussed previously, stranded costs should include the following categories of costs that are currently being incurred by utilities:

- generation assets and generation O&M costs
- purchase power agreements
- fuel contracts
- regulatory assets and liabilities
- generation-related A&G

A portion of a utility's power plant costs could become unrecoverable if market prices for retail generation services are not high enough to support full recovery of variable production costs (including fuel), fixed operation and maintenance costs, and all of the capital-related costs and generation-related A&G costs and regulatory assets and liabilities.

Generation-related regulatory assets include (but are not limited to) accounting reserves for various types of deferred costs related to: 1) the phase-ins of new power plants, 2) nuclear plant decommissioning costs, 3) deferred income

[11] See *RUCO's Response to the Stranded Costs Working Group Report*, September 25, 1997, page 9.

taxes, and 4) pension funds. Some of these regulatory assets may already be included in a utility's current rates, while others may not. Under traditional regulation, a utility would ultimately be likely to collect regulatory assets not yet in ratebase. Regulatory liabilities that are also not yet in rates might also impact stranded costs. Thus, regulatory assets and liabilities, including those not yet in rates, will contribute to stranded costs.

In addition, generation-related long-term legal obligations, such as purchased-power contracts and fuel supply contracts, could contribute to stranded costs if they exceed competitive market prices for comparable goods and services.

Finally, the utility's current costs of performing necessary functions and providing services that get wholesale bulk power to the retail end user (generation-related A&G costs) may be above or below the costs that competitive suppliers will incur to provide comparable retail generation services. A utility's above-market generation retailing costs will also contribute to stranded costs. On the other hand, if generation-related A&G costs are <u>below</u> the future level of the retail margin as is much more likely to be the case, stranded costs would be reduced.

Issue No. 4

Q. SHOULD THERE BE A LIMITATION ON THE TIME FRAME OVER WHICH STRANDED COSTS ARE CALCULATED?

A. Yes, there should be a limitation on the time frame over which stranded costs are calculated. Stranded cost estimates can be very sensitive to the time period over which they are calculated. The sensitivity occurs because stranded costs are based on the difference between the estimated embedded costs of generation and the estimated market prices of generation in each year during a specified time period, and these differences are likely to decrease over time and will most likely reverse. For example, the embedded cost-based generation rates for a utility may be significantly above the market price of power in the first year of the time period utilized. However, for most utilities, the embedded costs of existing generation service would be expected to decline over time due to depreciation and the fact that any new demand would be met with purchases from the market at market prices rather than with the construction of new utility-owned plants. Market prices may start low in the first year of the time period due to excess capacity, but will likely increase over time due to the tightening of available capacity. Therefore, the gap between embedded cost-based generation rates and market prices for power would narrow each year. If this trend of embedded cost-based generation rates declining faster than estimated market prices continued, then at some point embedded cost-based generation rates would fall below the market price for power. This would mean that there would be negative stranded costs on an annual basis in some of the later years. Therefore, if the stranded cost calculation is done over a reasonably long period, then the net stranded costs may be lower than if calculated over a shorter time period. To provide a fair estimate of net stranded costs, the calculation must be made over the expected lives of the generation assets, not a near-term period such as five years or less. Thus, unless demonstrated otherwise, stranded costs should be computed using a time period of at least 15 years, and perhaps as much as 25 years, depending on the expected life of the generation resources of a particular utility.

Issue No. 3.B

Q. WHAT ARE THE IMPLICATIONS OF FINANCIAL ACCOUNTING STANDARDS NO. 71 RESULTING FROM THE RECOMMENDED STRANDED COST CALCULATION AND RECOVERY METHODOLOGY?

A. The Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* defines a regulated entity, contains standards public utilities' financial statements must comply with, and allows regulators to create assets (regulatory assets) by deferring to future periods (by making recoverable in rates) certain current costs which would otherwise be charged to expenses under Generally Accepted Accounting Principles. Since SFAS No. 71 will be discontinued due to electric utility restructuring[12], and utilities would essentially have to charge to retained earnings all generation-related regulatory assets not in rates[13], this could have a significant impact on stranded costs. The nature of an asset may change due to the characteristics of its ultimate cost recovery[14], meaning that it is possible for the asset to continue being carried

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12 See Statement of Financial Accounting Standards No. 101, *Accounting for Discontinuation of Application of SFAS No. 71.*

13 Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona-Stranded Cost Working Group Report, p. 56.

14 Docket No. U-0000-94-165: Report to the Arizona Corporation Commission- In the Matter of the Competition in the Provision of Electric Service Throughout the State of Arizona-Stranded Cost Working Group Report, p. 58.

on the books of the utility as a distribution-based regulatory asset. If the ACC allows these assets to be recovered, they should be unbundled as part of stranded costs for generation.

Issue No. 7

Q. SHOULD THERE BE A TRUE-UP MECHANISM AND, IF SO, HOW WOULD IT OPERATE?

A. Yes, there should be a true-up mechanism and process established for adjusting stranded costs. Adjustment (or true-up) of initial stranded cost estimates would ensure that electric restructuring in Arizona is carried out in the public interest, and would ensure that stranded costs actually paid by ratepayers more accurately reflected actual retail market prices as they become known. This is critical in order to prevent ratepayers from paying certain stranded costs twice; once in a stranded cost recovery charge and once in the market price for generation. The amount of stranded cost recovery from ratepayers should be calculated administratively and trued-up annually (or at least bi-annually) to account for both actual retail market prices of generation and actual changes in what the regulated cost of generation would have been. The Commission could make a final review of stranded cost recovery at the end of the transition period to retail access, comparing the stranded costs being recovered through the Competitive Transition Charge (CTC) with the stranded costs actually incurred over the transition period based on the actual market prices experienced for retail generation services for each rate class. To repeat, at least three aspects of original derivation of the CTC may cause stranded cost recovered to differ from those incurred: (1) the cost assumptions used in preparing the stranded cost estimates (i.e. the market price) were inaccurate, (2) the forecast of electricity sales used to set the CTC (on a per-kWh basis) over the transition period was inaccurate, and (3) the projection of the unbundled generation component of current rates was inaccurate. These aspects should be periodically updated with historical information when reconciling the amount of stranded costs recovered in the true-up process.

A true-up mechanism not only protects ratepayers from paying too much in stranded cost recovery charges, but also protects ratepayers from the negative price effects (higher than competitive prices) of an immature competitive power market and/or from the exercise of market power.

Issue No. 9

Q. WHAT FACTORS SHOULD BE CONSIDERED FOR THE 'MITIGATION' OF STRANDED COSTS?

A. Utilities should be required to reduce potentially strandable generation costs as much as possible *before* Arizona takes steps towards allowing recovery of stranded costs. The utility should first focus attention on bringing the embedded cost of generation (including operating costs) closer to the market price for generation. Appropriate mitigation measures should fall into the category of cost reduction. Both cost shifting and revenue enhancement through load growth are not true mitigation measures. Reasonable and prudent mitigation efforts can vary between utilities and should therefore be evaluated on a case-by-case basis. However, the list of possible mitigation categories is long, and an evidentiary hearing may be necessary to identify all utility-specific mitigation potential. The list of possible mitigation categories includes:

- restructuring or refinancing existing debt
- renegotiating or buying out of power contracts, including non-utility generation (NUG) contracts, that do not have termination or release clauses
- selling excess generating capacity if it has more value in the market than it does to the current owner
- retiring uneconomic generating facilities if their operating costs exceed the price of replacing their output.
- improving economic efficiency and productivity of generation units

Thus, stranded cost mitigation measures should focus to the greatest extent possible on cost reduction. These measures should improve equity and/or economic efficiency, whereas cost shifting and revenue enhancement may not.

Q. PLEASE EXPLAIN WHY YOU STATE THAT STRANDED COST MITIGATION SHOULD NOT INCLUDE COST SHIFTING MEASURES.

A. Cost shifting measures do not constitute genuine attempts at mitigating stranded costs. Instead, these measures shift costs between utility shareholders and ratepayers, among customer classes, or among electricity services (such as between deregulated and regulated services). Examples of cost shifting include voluntary write-downs of excessive generating plant costs and accelerated depreciation schedules of plant or regulatory assets.

Issue No. 6

Q. HOW AND WHO SHOULD PAY FOR 'STRANDED COSTS' AND WHO, IF ANYONE, SHOULD BE EXCLUDED FROM PAYING STRANDED COSTS?

A. Payment of stranded costs should be made by all customers in each service territory according to tariff class. The charges for stranded cost recovery over time for each rate class should be determined through traditional cost-of-service rate design principles, and in particular, cost causation. For example, the economic portion of generation costs could be appropriately allocated to each customer class according to cost causation principles, as embodied in the inter-class cost allocators used in the last rate case. Then, the difference between this allocation of economic generation costs by customer class and the allocation of total generation costs by customer class that occurred in the last rate case would represent a fair allocation of stranded costs to each customer class. These principles applied would balance an energy charge and a demand charge so that equity is maintained. Tariffs for each rate class should continue to have the same billing determinants as they currently have. This approach would lead to a revenue neutral unbundling.

The payment of stranded costs should be made through a non-bypassable, nondiscriminatory "wires" charge or competition transition charge (CTC) which would tie the collection of stranded generation costs to the continued use of transmission or distribution service. The CTC would not vary, then, from supplier to supplier. Purchasing power from a competitive generation source should not impact a retail customer's obligation to pay for stranded costs. Competing suppliers would, therefore, have no competitive advantage or disadvantage based on recovery of the existing generation owner's stranded costs.

The CTC should be charged to customers on the basis of cost causation, as a natural consequence of using the revenue neutral approach to unbundling, as described above. The methodology implies that for those customer classes having both demand and energy-based components of its tariff, the CTC will also have both demand and energy components.

Q. RELATED TO THE PREVIOUS QUESTION REGARDING HOW AND WHO SHOULD PAY FOR 'STRANDED COSTS' IN GENERAL, SHOULD STRANDED COST BE SHARED BETWEEN RATEPAYERS AND STOCKHOLDERS?

A. Yes, in general, positive stranded costs should be shared between the ratepayers and stockholders. From a policy perspective, the key factor to consider in determining how to share stranded costs is equity. Considerations of equity would initially indicate that a 50/50 sharing would be appropriate. The extent to which the recovery of stranded costs is shared between ratepayers and utility stockholders is critical to lowering rates for all customers in the short- to medium-term under retail competition. First, the ACC should consider on a utility-by utility basis what factors led to stranded costs that might have been significantly under the control of each utility, and what ratemaking treatment the assets with uneconomic costs have received since their inclusion in the utility's ratebase. Then, the ACC should determine whether stockholders should be held responsible for substantially more than 50 percent of stranded costs. The Commission should first decide on the appropriate percentage sharing for each generating asset which contributes to stranded costs, based on the causes of the stranded costs and the historic ratemaking treatment of each asset. Then the Commission should weigh these results together to get an overall system-wide percentage sharing. Retail ratepayers should not be held responsible for more than 50 percent of a utility's prudent stranded generation costs, unless special considerations are necessary to maintain the financial integrity of the utility. Recovery should be based on a lower rate of return through use of a bond rate, not an equity rate which includes a risk premium.

Issue No. 5

Q. SHOULD THERE BE A LIMITATION ON THE RECOVERY TIME FRAME FOR 'STRANDED COSTS'?

A. The time frame for stranded cost recovery should be determined prior to commencing the recovery process. Assuming that a wires charge would be used for recovery, the time frame should depend on 1) the magnitude of the net present value of the utility's stranded costs that need to be recovered from ratepayers, 2) the estimated level of electricity demand on the utility's distribution system in future years, 3) the utility's discount rate, and 4) keeping the strandable cost recovery charge within reasonable limits so that a customer's total electric rate relative to the rate currently paid under regulation is reduced to an appropriate level. Generally, the longer the period allowed for recovery, the smaller the stranded cost recovery charge would be. A longer recovery period could, therefore, allow for greater rate reductions in the early years of the recovery period. But a longer recovery period also may delay the enjoyment of the full potential savings brought about through a competitive generation market.

Q. GIVEN ALL RELEVANT CONSIDERATIONS, WHAT MAXIMUM TIME FRAME WOULD YOU RECOMMEND FOR STRANDED COST RECOVERY?

A. Based on the trade-offs and considerations just mentioned, I recommend that the time frame for recovering stranded costs from ratepayers be less than ten years. Ten years should be the maximum recovery period, even for utilities with high stranded costs. However, if stranded costs are modest relative to the size of a utility, then all stranded costs should be able to be recovered within a five year period, or less. For Arizona, this should imply full recovery by January 1, 2003, which is the start date for full retail access. If necessary, the recovery charge should be designed to be constant in real dollars, thus enabling near-term rates to be lower than if the stranded cost recovery charge were levelized in current dollars. The recovery period, the recovery mechanism, and the amount of sharing should be structured so that in the early years of the recovery period, retail ratepayers taking the standard offer service see a rate reduction. Note that even if strandable costs are non-existent, just re-setting generation rates for Standard

Offer Service at a market-based retail rate would likely allow for a significant rate reduction.

Issue No. 8

Q. SHOULD THERE BE PRICE CAPS OR A RATE FREEZE IMPOSED AS PART OF THE DEVELOPMENT OF A STRANDED COST RECOVERY PROGRAM AND IF SO, HOW SHOULD IT BE CALCULATED?

A. I recommend that a price cap, as opposed to a rate freeze, be imposed by the ACC during the transition period. Capping the rate for the standard offer generation service at the lower of the generation rate that would have been charged to each customer class if retail competition had not been introduced in Arizona, or the market price for retail generation services appropriate to that customer class is recommended. If this is done during the transition period, it would guarantee that during the transition to retail competition, customers will be at least as well off as they would have been under continued cost of service rate regulation. This will also ensure that ratepayers do not pay for any generation costs twice, once in the rates for standard offer of service and again in the stranded cost recovery charge. This approach will allow all customers to enjoy the rate benefits of retail competition during the transition period. Use of a market price to set the retail generation cap will also provide a degree of customer protection in the event that a utility wishes to deregulate any of the generation assets used to serve standard offer customers.

Issue No. 1

Q. SHOULD THE ELECTRIC COMPETITION RULES BE MODIFIED REGARDING STRANDED COSTS, IF SO, HOW?

A. Yes, I believe that the set of policies and principles that I have recommended above imply that many modifications to the electric competition rules need to be made. The following questions pertain solely to the changes that I am recommending in the Rules.

Q. DO YOU AGREE WITH THE DEFINITION OF STRANDED COSTS IN THE RULES?

A. No, I recommend that the definition of stranded costs be clarified. In Section R14-2-1601, stranded costs are defined as,

> "the verifiable net difference between a) the value of all the prudent jurisdictional assets and obligations necessary to furnish electricity (such as generating plants, purchased power contracts, fuel contracts, and regulatory assets), acquired or entered into prior to the adoption of this Article, under traditional regulation of Affected Utilities, and b) the market value of those assets and obligations directly <u>attributable to the introduction of competition under this Article</u>."

This definition of stranded costs only includes changes in asset value due to the introduction of competition under Article 16 of the Rules, but does not refer directly to the total of the uneconomic costs associated with a utility's generation resources as *strandable* costs that exist whether or not retail competition is established. The existing uneconomic costs associated with a utility's generation resources have already been incurred and are presently part of its regulated embedded costs of service. Therefore, all existing uneconomic generation costs are currently being recovered through the bundled rates paid by all retail customers. These uneconomic costs are not stranded yet, but are strandable and could become stranded if there is retail competition. Therefore, the definition of stranded costs in Section R14-2-1601 should be reworded as:

> "the uneconomic portion (net sunk generation costs plus unavoidable prospective costs associated with a utility's generation that cannot be recovered in a competitive market) of a utility's costs for owning and operating its power plants, long-term purchase power contract costs, fuel supply contract costs, generation-related regulatory assets, and regulatory assets and liabilities that are generation-related but are not recoverable under competition as defined by the verifiable net difference between a) the value of all the prudent jurisdictional assets, obligations and costs necessary to furnish electricity, acquired or entered into prior to the adoption of this Article, under traditional regulation of Affected Utilities, and b) the market value of those assets and obligations."

Q. DO YOU RECOMMEND ANY CHANGES TO SECTION A or B of R14-2-1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED UTILITIES?

A. Yes, I recommend the following modifications:

Section A states that,

> "Affected Utilities shall undertake every feasible, cost-effective measure to mitigate or offset stranded costs by means such as expanding wholesale or retail markets, or offering a wider scope of services for profit, among others."

I disagree because I do not believe that increasing the total load by expanding wholesale or retail markets is a proper mitigation measure. Expanding sales does not necessarily reduce the total value of stranded costs. More appropriate mitigation measures comprising cost reduction should be mentioned by way of example in this article, including such measures as improving the economic efficiency and productivity of generation plants, selling excess generating capacity, and renegotiating or buying out of uneconomic power contracts, including non-utility generation (NUG) contracts. Section A. should also make explicit the time frame in which mitigation measures should occur. Utilities should be required to reduce and mitigate potentially strandable generation costs as much as possible before Arizona takes steps to allocate recovery of stranded costs. Therefore, I would reword this section of the Rules to say the following:

> "The Affected Utility shall take every feasible, cost-effective measure to mitigate or reduce stranded costs before steps are taken by the ACC to allocate recovery of stranded costs through cost reduction measures such as improving the economic efficiency and productivity of generation plants, selling excess generating capacity, and renegotiating or buying out uneconomic power contracts, including non-utility generation (NUG) contracts."

In addition, Section B states:

> "the Commission shall allow recovery of unmitigated Stranded Cost by Affected Utilities."

Unfortunately, this section appears to require 100 percent stranded cost recovery after mitigation, implying that no sharing of stranded costs between ratepayers and stockholders is appropriate. I strongly disagree with this aspect of the Rules and believe that at the very least, the Rules must allow for the possibility of sharing, as determined by the ACC. In fact, I advocate that stranded costs should be shared between both ratepayers and shareholders.[15] As discussed

[15] It is important to note that taxpayers will also "pay" a portion of stranded cost recovery if some allocation is made to shareholders. Reduction of utilities' federal and state income taxes due to

earlier, allocating 50 percent to ratepayers and 50 percent of the stranded costs of shareholders is a recommended baseline for stranded cost allocation. An important factor in determining the appropriate sharing is how much ratepayers have already paid (on a present value basis) toward stranded costs to Arizona's utilities. The ACC should consider on a utility-by-utility basis what factors led to stranded costs and what ratemaking treatment the assets with uneconomic costs have received since their inclusion in the utility's ratebase. Therefore, this section of the Rules should be reworded to say:

> "The Commission shall consider, on a utility-by-utility basis, what factors led to the existence of stranded costs, what ratemaking treatment the assets with uneconomic costs have received since their inclusion in the ratebase and, therefore, what the appropriate percentage sharing between ratepayers and stockholders for each generating resource which contributes to stranded costs should be, and shall then allow for the recovery of the appropriate portion of unmitigated stranded costs by Affected Utilities."

Q. DO YOU RECOMMEND ANY CHANGES TO SECTIONS C OR D of R14-2-1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED UTILITIES?

A. No, I have no proposed changes to Sections C or D.

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the partial write-off of stranded costs actually results in a sharing of those costs between the utility shareholders, ratepayers, and taxpayers. To the extent that taxpayers and electricity ratepayers are the same households or businesses, they may contribute to stranded cost recovery through two mechanisms.

Q. DO YOU RECOMMEND ANY CHANGES TO SECTION E, F, G or H of R14-2-1607 ON THE RECOVERY OF STRANDED COSTS OF AFFECTED UTILITIES?

A. I have no comments or proposed changes for Sections E, F or G. But, I do have recommendations regarding Section H. Section H. states,

> "An Affected Utility shall request Commission approval of distribution charges or other means of recovering unmitigated Stranded Costs from customers who reduce or terminate service from the Affected Utility as a direct result of competition governed by this Article, or who obtain lower rates from the Affected Utility as a direct result of the competition governed by this article."

I agree that the ACC must approve stranded cost recovery charges for customers who receive generation services from alternative suppliers to their local distribution utility, but believe that use of a wires charge paid by <u>all</u> customers of the distribution utility as part of a proper unbundling of rates will solve this problem.[16] The wires charge should be applied by the local distribution company, and therefore stranded costs would be allocated to all customers being served by the local distribution system. Both standard offer customers and those being supplied by alternative suppliers as a result of competition will pay for stranded costs on an equitable basis due to a wires charge. Therefore, Section H should be reworded so that,

> "Unmitigated Stranded Costs eligible for recovery shall be recovered both from customers who reduce or terminate <u>generation</u> service from the Affected Utility as a direct result of competition governed by this Article by taking generation service from alternative suppliers, as well as from customers who stay with

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16 Thus far, all states have taken this approach.

standard offer service, through a non-bypassable, nondiscriminatory wires charge."

Q. DO YOU RECOMMEND ANY CHANGES TO SECTION I OF R14-2-1607 ON THE RECOVERY OF STRANDED COSTS BY AFFECTED UTILITIES?

A. I offer the following comments on Section I. Section I begins with,

> "The Commission shall, after hearing and consideration of analysis and recommendations presented by the Affected Utilities, staff, and intervenors, determine for each Affected Utility the magnitude of Stranded Cost, and appropriate Stranded Cost recovery mechanisms and charges, the Commission shall consider at least the following factors:"

No. 1) The impact of Stranded Cost recovery on the effectiveness of competition. As stated above, I believe there will be no impact on stranded cost recovery if recovery is made through a non-bypassable wires charge paid by all customers.

Pertaining to item No. 2), which refers to "The impact of Stranded Cost recovery on customers of the Affected Utility who do not participate in the competitive market," if a wires charge is adopted, then customers who do not participate in competition are subject to the same recovery of stranded costs as customers who do participate. Therefore, the recovery of stranded costs via a wire charge is equitable.

No. 3) refers to "the impact, if any on the Affected Utility's ability to meet debt obligations." I believe there will be no significant impact on debt repayment even if there is significantly less than 100 percent stranded cost recovery.

No. 4) states "The impact of Stranded Cost recovery on prices paid by consumers who participate in the competitive market." The impact of stranded cost recovery will add to the total price of electricity, but will not result in a competitive disadvantage.

No. 6) "The degree to which the Affected Utility has mitigated or offset Stranded Costs," would be taken into account in my proposed approach.

No. 7) "Appropriate treatment of negative costs" implies that a net system approach is taken whereby negative stranded costs are netted against positive stranded costs.

I also wish to clarify No. 9). I do not believe that "The ease of determining the amount of stranded costs" should be a significant factor when hundreds of millions of dollars are at stake. Even a sale price must be evaluated by the Arizona Corporation Commission (ACC) on an administrative basis to determine reasonableness with relation to projected market prices. I propose deleting No. 9), as I do not think it is relevant to the Commission's determination of mechanisms and charges relevant to stranded costs.

No. 10) mentions "The applicability of Stranded Cost to interruptible customers." Stranded costs are highly relevant to interruptible customers since most stranded costs are related to baseload plant and should be calculated on a per- kWh basis for the energy used by interruptible customers.

No. 11), which states "The amount of electricity generated by renewable generating resources owned by the Affected Utility," is only directly relevant if these resources are priced above market. This depends on whether or not there is a renewable generation requirement under restructuring in Arizona. Section R14-2-1609 of the Rules refers to a solar portfolio standard, which may be referenced in No. 11).

The critical element missing in Section I is related to the provision of standard offer service. In pricing its standard offer service, the incumbent utility should use the retail price of generation as the baseline. If the utility offers standard offer service at rates below the retail price of generation, competition among generation service providers will not occur. The use of the retail price of generation as the baseline for setting the price for the Standard Offer Service should not be just a "consideration," but a requirement on the part of the utility in establishing its Standard Offer. The Commission should include this in consideration of recovery mechanisms and stranded cost determinations by adding, as a "consideration" No. 12).

> 12) The use of a retail price of generation as a baseline for establishing the price of Standard Offer Service.

Q. DO YOU RECOMMEND ANY CHANGES TO SECTION J OF R14-2-1607 ON THE RECOVERY OF STRANDED COSTS BY AFFECTED UTILITIES?

A. I believe that Section J should be clarified. Section J states,

> "Stranded costs may only be recovered from customer purchases made in the competitive market using the provisions of this Article. Any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand-side management, or other demand reduction attributable to any cause other than the retail access provisions of this article shall not be used to calculate or recover any Stranded Cost from a consumer."

I agree with this basic position. Recovering stranded costs from a customer for load reductions due to technological change implies the use of an exit fee and is not appropriate. Exit fees are problematic for several reasons. First, the lump sum payment (however it is determined) could create an insurmountable financial barrier for some customers. Secondly, there is no regulatory precedent for charging for stranded costs, or any costs, for power not purchased from the utility. If a customer reduces its load, regulatory policy should not attempt to distinguish among the various possible causes of such load reduction by imposing an exit fee if the reduction is due to the increased self-generation of power, but not imposing that fee if the load reduction is due to energy conservation effects, or shutting down an assembly line. Therefore, Section J should be restated as,

> "Stranded costs will be recovered from all customers continuing to use the distribution system based on the amount of generation purchased from any supplier. Any reduction in electricity purchased from an Affected Utility resulting from self-generation, demand-side management, or other demand reduction attributable to any cause shall not be used as the basis to recover Stranded Costs from a consumer."

Q. DO YOU RECOMMEND ANY CHANGES TO SECTIONS K AND L OF R14-2-1607 ON THE RECOVERY OF STRANDED COSTS BY AFFECTED UTILITIES?

A. I have no recommended changes for Section K. Regarding Section L, which states, "The Commission may order regular revisions to estimates of the magnitude of Stranded Cost," I agree that the ACC should revise stranded cost estimates, and recommend this be achieved through a periodic true-up mechanism, as stated previously. The amount of stranded cost recovery from ratepayers should be calculated administratively and trued-up annually (or bi-annually) to account for the actual market prices of generation. Please refer to the question above on the true-up mechanism for further discussion of this issue.

Q. DO YOU RECOMMEND ANY CHANGES TO ANY SUB-SECTIONS OF RULE R14-2-1606 WHICH ARE REQUIRED IN ORDER TO IMPLEMENT THE STRANDED COST RELATED POLICY ISSUES THAT YOU HAVE DISCUSSED ABOVE?

A. Yes, I recommend that No. 1 of Section B on Standard Offer Tariffs in Section R14-2-1606 be changed. This section currently states,

> 1. By the date indicated in R14-2-1602, each Affected Utility may file proposed tariffs to provide Standard Offer Bundled Service and such rates shall not become effective until approved by the Commission. If no such tariffs are filed, rates and services in existence as of the date in R14-2-1602 shall constitute the Standard Offer.

To freeze rates at their December 31, 1997 level does not benefit customers on the Standard Offer, and may inhibit the process of competition. A price cap on the generation rate is necessary during the transition to completely unregulated generation markets in order to protect ratepayers from any adverse effects of the unregulated generation market during this time period. The rate cap should be at or below the level that rates would have been under continued regulation. The Standard Offer should further provide customers with a rate reduction below the rate cap. Therefore No. 1 of Section B should be reworded to say:

> 1. By July 1, 1998, each Affected Utility must file proposed tariffs to provide Standard Offer Service and such rates shall not become effective until approved by the Commission. The Standard Offer rate should be set at a level below the level at which rates were on December 31, 1997, and below the rate cap which should be established by the ACC for the transition period (January 1, 1999-January 1, 2003). The generation component of the Standard Offer Service should be set by the ACC at a market-based level for retail generation services.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Education

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B.S.	Physics and Philosophy, M.I.T., 1966

Experience

1997-present	Manager of Electricity Group, Tellus Institute.
1993-1997	Director of Energy Group, Tellus Institute.
1991-present	Director of Planning, Tellus Institute.
1977-present	Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modelling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning.
1978-1980	Consultant to Brookhaven National Laboratory.
1979	Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee.
1976-1978	Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory.
1974-1976	National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York.
1973	Instructor, Putney - Antioch Graduate School.

Testimony

Agency	**Case or Docket No.**	**Date**	**Topic**
New Jersey Office of Administrative Law	BPU E097070 456 OAL PUC 7311-97 (Tellus 97-203/A6)	Nov. 1997	Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric)
New Jersey Office of Administrative Law	BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97 (Tellus 97-203/A3)	Nov. 1997	Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy)
New Jersey Office of Administrative Law	BPU E09707 0462 OAL PUC-7347-97 BPU EO9707 0461 OAL PUC-7348-97 (Tellus 97-203/A1)	Nov. 1997	Pricing of retail geneartion services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company)
Public Utility Commission of Texas	473-96-2285 and 16705 Tellus 97-046)	Sept. 1997	Competitive issues
Michigan Public Service Commission	U-11283 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test

Michigan Public Service Commission	U-11337 (Tellus 97-093)	May 1997	Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test
New York Public Service Commission	96-E-0898 (Tellus 97-009)	May 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition
New York Public Service Commission	96-E-0897 (Tellus 97-009)	April 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power
New York Public Service Commission	96-E-0891 (Tellus 97-009)	February 1997	Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power
Missouri Public Service Commission	EM-96-149 (Tellus 96-214)	Nov. 1996	Various issues related to market power
Federal Energy Regulatory Commission	EC96-10-000 (Tellus 96-050F)	Sept. 1996	Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization
Maryland Public Service Commission	8725 (Tellus 96-050)	July 1996	Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization

Illinois Commerce Commission	95-0551 (Tellus 95-302)	March 1996	Review of joint application of Central Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization
Vermont Public Service Board	5724 (Tellus 94-064)	July 1994	Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio
Illinois Commerce Commission	94-0065 (Tellus 94-112A)	June 1994	Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment
		July 1994	Rebuttal Testimony in above docket
Kansas Corporation Commission	180,056-U	February 1994	Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities
Public Utilities Commission of Hawaii	7257 (Tellus 93-144A3)	December 1993	Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning
Arkansas Public Service Commission	93-132-U (Tellus 93-148)	November 1993	Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River
		January 1994	Sur-Rebuttal Testimony in above docket
Public Utilities Commission of Georgia	4152-U (Tellus 93-100)	August 1993	Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company

Pennsylvania Public Utility Commission	A-110300 F. 051 (Tellus 92-026)	July 1993	Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation
Public Utilities Commission of Ohio	91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165)	April 1993	Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report
Georgia Public Service Commission	4133-U, 4136-U (Tellus 92-078)	October 1992	Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995
Public Utilities Commission of Ohio	92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A)	September 1992	Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process
Public Service Commission of the State of Georgia	4131-U, 4136-U (Tellus 91-266)	June 1992	Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO)
U.S. Bankruptcy Court - Manchester, NH	BK-91-11336 Chapter 11	March 1992	Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc.
Public Utilities Commission of Ohio	91-410-EL-AIR (Tellus 91-082)	December 1991	Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)

Public Utilities Commission of Ohio	92-418-EL-AIR (Tellus 91-091)	December 1991	Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO)
Maine Public Utilities Commission	89-193, 89-194, 89-195 (ESRG 89-189B & 90-039)	August 1990	Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids.
New Hampshire Public Utilities Commission	DF 89-085 (ESRG 90-051)	July 1990	Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers
		September 1990	Supplemental Testimony in above docket.
Florida Public Service Commission	891345-EI (ESRG 90-017)	April 1990	Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit.
Michigan Public Service Commission	U-9458 (ESRG 89-158)	February 1990	Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan.
Vermont Public Service Board	5330 (ESRG 89-078)	December 1989	Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.*
		February 1990	Further Testimony in above Docket
		February 1990	Surrebuttal Testimony in above Docket
Pennsylvania Public Utility Commission	R-891364 (ESRG 89-90A)	October 1989	Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit.
Florida Public Service Commission	881167-EI (ESRG 89-034)	May 1989	Ratebase Treatment of Gulf Power Scherer 3 Capacity

Federal Energy Regulatory Commission	ER88-630-000 (ESRG 88-153)	April 1989	Pass Through of Performance Incentive Program Charges by New England Power Company
Public Service Commission of the District of Columbia	Formal Case No. 877 (ESRG 88-128D)	February 1989	Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO
	(ESRG 88-128E)	March 1989	Rebuttal Testimony
Michigan Public Service Commission	U-8871 (ESRG 88-32)	April 1988	Review of the Appropriate Avoided Costs for the CPCo System
	(ESRG 88-32A)	August 1988	Rebuttal Testimony
Maine Public Utilities Commission	87-268 (ESRG 30A)	April 1988	Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power
	87-268 (ESRG 87-30A1)	August 1988	Supplemental Testimony
Pennsylvania Public Utility Commission	M-870111, G-870087 G-870088 (ESRG 88-01)	February 1988	Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs
Pennsylvania Public Utility Commission	R-870732 (ESRG 87-80)	November 1987	Investigation into Pennsylvania Power Company's Share of Perry 1 Nuclear Unit and Assessment of Physical Excess Capacity. Direct and Rebuttal Testimony.
Michigan Public Service Commission	U-7830 (ESRG 85-35E)	December 1987	Review of the Application of Consumers Power Company to Recover Its Midland Investment

Pennsylvania Public Utility Commission	R-870651 (ESRG 87-50D)	October 1987	Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System.
Federal Energy Regulatory Commission	ER-86-694-001	September 1987	Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission
Maine Public Utilities Commission	86-85	June 1987	Investigation of Reasonableness of Rates
		August 1987	Surrebuttal
Maryland Public Service Commission	7972	February 1987	Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company
Arizona Corporation Commission	U-1345-85-367 (Tellus 86-42B)	February 1987	Concerning the Prudence of Palo Verde Investment
Michigan Public Service Commission	U-8578	January 1987	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8585	January 1987	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Pennsylvania Public Utility Commission	R-860378 (Tellus 85-083A)	September 1986	Economics of Duquesne Light Company's Share of Perry 1
		November 1986	Surrebuttal
Pennsylvania Public Utility Commission	R-850267 (Tellus 85-083B)	September 1986	Economics of Penn Power's Share of Perry 1
		November 1986	Surrebuttal

		March 1987	Supplemental
Michigan Public Service Commission	U-8348	July 1986	Palisades Performance Standards
Michigan Public Service Commission	U-8291	April 1986	Power Supply Cost Recovery Plan for Detroit Edison
Michigan Public Service Commission	U-8286	February 1986	Power Supply Cost Recovery Plan for Consumers Power
Michigan Public Service Commission	U-8297	January 1986	Power Supply Cost Recovery Plan for Upper Peninsula Power Company
Michigan Public Service Commission	U-8285	January 1986	Power Supply Cost Recovery Plan for Indiana & Michigan Company
Division of Public Utilities, Dept. of Business Regulation	85-2011-01 85-999-08	January 1986	Construction of a Transmission Line and Transmission Facilities in Southwestern Utah
New York Public Service Commission	28252	October 1985	Shoreham - Rate Moderation
		January 1986	Surrebuttal
Missouri Public Service Commission	ER-85-128 EO-85-185 EO-85-224 (Tellus 83-080)	June 1985	Wolf Creek Excess Capacity and the Prudency of Company Planning
Federal Energy Regulatory Commission	ER-84-560-000 (Tellus 85-019)	April 1985	Callaway Excess Capacity and a Review of Union Electric Planning
State Corporation Commission of the State of Kansas	120-924-U 142-098-U 142-099-U 142-100-U	April 1985	General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas

Michigan Public Service Commission	U-8042	February 1985	Power Supply Cost Recovery Plan for Consumers Power Company
Michigan Public Service Commission	U-8020	January 1985	Power Supply Cost Recovery Plan for Detroit Edison Company
Massachusetts Department of Public Utilities	84-49, 84-50, 84-140, 627, 1656 & 1957	January 1985	Economics of Completing Seabrook 1 for Four Massachusetts Utilities
Michigan Public Service Commission	U-7830(M)	December 1984	Future Capacity Requirements of Consumers Power Company
New Hampshire Public Utilities Commission	84-200	November 1984	Investigation of Public Service Company of New Hampshire Financing Plan to Complete Construction of Seabrook 1
Michigan Public Service Commission	7830	October 1984	In the Matter of the Application of Consumers Power Company for Authority to Increase its Rates Applicable to the Sale of
Electricity			
Maine Public Utilities Commission	84-113	September 1984	Investigation of Seabrook Involvement by Maine Utilities
Missouri Public Service Commission	ER-84-168	August 1984	In the Matter of Union Electric Company of St. Louis, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company
Michigan Public Service Commission	U-7785	April 1984	In the Matter of the Application of Consumers Power Company for Approval of a Power Supply Cost Recovery Plan and for Authorization of Monthly Power Supply Cost Recovery Factors for Calendar Year 1984
Ohio Power Siting Board	02-00022	February 1984	In the Matter of the Cleveland Electric Illuminating Company/Ohio Edison Company Amended Application to Construct and Operate a Transmission Facility Identified as the Perry-Hanna 345 kV Transmission Line

Michigan Public Service Commission	U-7775	February 1984	In the Matter of the Application of Detroit Edison Company to Implement a Power Supply Recovery Plan in its 1984 Electrical Rates
Maine Public Utilities Commission	81-276	July 1983	As to the Avoided Costs for Cogeneration and Small Power Production Facilities on the Maine Public Service Company System
South Carolina Public Service Commission	82-352-E	June 1983	Review of A.S. Beck Analyses Regarding the Economics of the Catawba Nuclear Station
North Carolina Utilities Commission	E-2, Sub 461	June 1983	Application by Carolina Power and Light Company for Increase in Electric Rates
Michigan Public Service Commission	U-7550	May 1983	Application of Detroit Edison Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Michigan Public Service Commission	U-7512	April 1983	Application of Consumers Power Company for Authority to Implement a Power Supply Recovery Plan in its 1983 Recovery Rates
Pennsylvania Public Utilities Commission	R-822169	March 1983	Excess Capacity for Pennsylvania Power & Light Company
North Carolina Utilities Commission	E-100, Sub 47	February 1983	Power Plant Performance Standards and and Fuel Adjustment Clauses
Federal Energy Regulatory Commission	ER82-481 1982	December Options	Overview of Conservation and Generation
Kentucky Public Service Commission	83-14	December 1982	Review of the Kentucky-American Water Company Capacity Expansion Program
Maine Public Utilities Commission	81-276	December 1982	As to the Avoided Costs for Cogeneration and Small Power Producers
Maine Public Utilities Commission	81-114	November 1982	Maine Public Service Company Investigation of Power Supply Planning and Purchases

Maine Public Utilities Commission	82-174	October 1982	Capital Costs of the Seabrook Nuclear Units
Indiana Public Service Commission	36818	October 1982	An Economic Assessment of the Marble Hill Nuclear Station
New Hampshire Public Utilities Commission	DE81-312	October 1982	Investigation Into Supply and Demand of Electricity for Public Service Company of New Hampshire
Michigan Public Service Commission	U-6923	May 1982	Consumers Power Company Electricity Case
Alabama Public Service Commission	18337	January 1982	Long-Range Capacity Expansion Analysis
State of New York Energy Planning Board	SEMP II Hearings	November 1981	Conservation and Generation Planning
Pennsylvania Public Utility Commission	80100341	September 1981	Operating and Capital Costs: Limerick Nuclear Station; Surrebuttal
Maine Public Utilities Commission	MPUC 80-189	April 1981	Electric Energy Costs: Seabrook Nuclear Power Plants; Surrebuttal
Pennsylvania Public Utility Commission	I-80100341	February 1981	Operating and Capital Costs: Limerick Nuclear Generating Station
Ohio Public Utilities Commission	80-141 EL-AIR	December 1980	CAPCO Construction Program; Generation Planning
Michigan Public Service Commission	U-6360	September 1980	Generation Expansion Planning: Consumers Power Company
Pennsylvania Public Utility Commission	I-79070315	August 1980	CAPCO Construction Schedule; Surrebuttal
Connecticut Power Facility Evaluation Council	F-80	June 1980	Renewable Resource Electric Generation in Connecticut
Pennsylvania Public Utility Commission	I-79070317	March 1980	CAPCO: Generation Planning and Reliability

Michigan Public Service Commission	U-5979	June 1979	Forecast Critique and Adjustments: Consumers Power Company
Massachusetts Dept. of Public Utilities	19494	August 1978	Long-range Electric Demand Forecast: Boston Edison Company
Pennsylvania Public Utility Commission	438	March 1978	Long-range Forecast of Electric Energy and Demand (Philadelphia Electric Company)

Tellus Research

November 1997 — *Restructuring the Electric Industry in Delaware.* A Draft Report by the Delaware Public Service Commission Staff. PSC Docket No. 97-229. Tellus Study No. 96-099. Co-author. Final Draft Report.

February 1997 — "Modeling Electricity Pricing in a Deregulated Generation Industry: The Potential for Oligopoly Pricing in a Poolco," submitted to *Energy Journal.* Co-author.

January 1997 — *Sustainable Electricity for New England: Developing Regulatory and Other Governmental Tools to Promote and Support Environmentally-Sustainable Technologies in the Context of Electric Industry Restructuring.* The R/EST Project. A report to the New England Governors' Conference, Inc. Tellus No. 95-310. Project manager.

October 1996 — *Comments on FERC's CRT NOPR in Docket No. RM96-11-000.* Submitted to: The National Association of State Utility Consumer Advocates. Tellus Study No. 96-142. Principal investigator.

January 1996 — *Achieving Efficiency and Equity in Nevada's Electric Industry - Comments Submitted by the Attorney General's Office of Advocate for Customers of Public Utilities on Issues Posed by the State Assembly in A.C.R. #49 Directing a Study of Competition in the Generation, Sale, and Transmission of Electricity.* Tellus Study No. 95-153A1. Co-author.

December 1995 — *Promoting Environmental Quality in a Restructured Electric Industry.* A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. Co-author.

October 1995 — *Power Pools and Least-Cost Compliance with the Clean Air Act.* A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. Principal investigator.

September 1995	*Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities.* Tellus Study No. 93-251. Principal investigator.
September 1995	Discussion Paper: An Overview of the Generic Issues Related to the Amendment to Illinois Senate Bill 1058. Submitted to the Illinois Consumer Utility Board. Tellus Study No. 95-210.
September 1995	Tellus' Initial Comments on CEEP's Discussion and Conclusions of its Electric Competition Investigation (PA PUC Docket No. I-940032). Submitted to: Pennsylvania Office of Consumer Advocate. Tellus Study No. 94-012. Co-author.
May 1995-Present	*Analysis of Economics of the Sherman Biomass Generating Unit.* Prepared for: Wheelabrator Environmental Systems, Inc. Tellus Study No. 95-154. Co-author.
March 1995	*Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.* Public Service Commission of the District of Columbia. Tellus No. 94-051.
January 1995	*Order on Application for Reconsideration, Formal Case No. 813, Order No. 10554.* Public Service Commission of the District of Columbia. Tellus No. 94-051.
January 1995	In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. Co-author.
October 1994	*Competition and the Tennessee Valley Authority.* White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. Co-author. Draft.
May 1994- December 1995	Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. Project Manager.
December 1994	*Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.* Submitted to: Pennsylvania Office of Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. Co-author.
November 1994	"Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with SO_2 Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory

	Commission. Tellus Study No. 94-113. Co-author.
September 1994	*Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. Co-author.
April 1994	*Review of Union Electric Company's Electric Utility Resource Planning Compliance Filings.* Prepared for: The Missouri Office of Public Counsel. Tellus Study No. 93-300. Co-author.
December 1993	*Aligning Rate Design Policies with Integrated Resource Planning.* A report to: National Association of Regulatory Utilities Commissioners. Tellus Study No. 92-047. Co-author.
August 1993	A Report to: The Public Service Commission of the State of Delaware Regarding Docket 35: Adoption of the Guidelines for Integrated Resource Planning by Electric Cooperatives. Tellus Study No. 93-053. Co-author.
August 1993	A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. Co-author.
July 1993	*IRP Concepts and Approaches.* Report to Hydro-Quebec and the Public Interest Groups and Associations. Tellus Study No. 92-155. Project Manager.
June 1993	*Proposed Rules Governing Integrated Resource Planning for Electric and Natural Gas Utilities Regulated by the State of Kansas.* In collaboration with Kansas Corporation Commission Staff. Tellus Study No. 92-105. Project Manager.
May 1993	*Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company Ltd.* Prepared for Consumers Gas Company, Ltd. Tellus No. 91-001. Project Co-manager. Not publicly available.
January 1992	*Sales Forecasts and Price Changes for New Hampshire Electric Cooperative.* Prepared for: Members Committee of New Hampshire Electric Cooperative. Tellus Project No. 91-173. Principal investigator.
September 1991	*America's Energy Choices: Investing in a Strong Economy and a Clean Environment.* In collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy. Tellus Study No. 90-067. Co-author.
September 1990	*Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management.* Tellus No. 90-028A. Co-author.

July 1990	*Assessment of the Eastern Utilities Associates' Plan to Acquire UNITIL Corporation: Issues Affecting New Hampshire Consumers.* Exhibit 2 to Tellus No. 90-051. Project manager.
April 1990	*Comments on Pacific Power and Utah Power Resource and Market Planning Program.* On behalf of Committee of Consumer Services, Utah Department of Commerce. ESRG No. 90-050A. Author.
March 1990	*The Northeast Utilities Plan for Public Service Company of New Hampshire: Issues Affecting New Hampshire Consumers.* A report to: State of New Hampshire, Office of the Consumer Advocate. ESRG No. 90-019. Reviewer.
December 1989	*The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.* A Report to the Vermont Public Service Board. ESRG No. 89-078. Principal investigator.
July 1989	*Rhode Island's Options for Electric Generation.* A Policy Statement of the Energy Coordinating Council. ESRG No. 89-004. Co-author.
March 1989	*Update of 1985 Study on the Economics of Closing vs. Operating Shoreham.* ESRG Report No. 89-051. Principal investigator.
July 1988	*The Cost to Ratepayers of the Proposed LILCO Settlement.* A Report to Suffolk County. ESRG Report No. 88-23. Co-author.
April 1988	*An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec.* A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. Principal Investigator.
June 1987	*NEPOOL and New England's Electricity Future: Issues and Directions.* A Report to the New Hampshire Consumer Advocate. ESRG Study No. 86-83. Co-author.
May 1986	*Midland Options Study - A Response.* A report to the Michigan Department of the Attorney General. ESRG Study No. 85-35. Principal Investigator.
September 1984	*The Economics of Seabrook 1 from the Perspective of the Three Maine Co-Owners.* ESRG Study No. 84-38. Principal Investigator.
May 1984	*Power Planning in Kentucky: Assessing Issues and Choices. Project Summary Report to the Public Service Commission.* ESRG Study No. 83-51. Project manager.

April 1984	*Power Planning in Kentucky: Assessing Issues and Choices. Generation and Transmission System Planning.* ESRG Study No. 83-51/TR II. Project manager. Principal investigator.
April 1984	*Power Planning in Kentucky: Assessing Issues and Choices. Utility Financial Forecasts: Two Case Studies.* ESRG Study No. 83-51/TR IV. Project manager.
April 1984	*Draft Report: Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.* ESRG Study No. 83-81. Principal investigator.
January 1984	*Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant.* ESRG Study No. 83-10.
January 1984	*Power Planning in Kentucky: Assessing Issues and Choices. Conservation as a Planning Option.* ESRG Study No. 83-51/TR III. Project manager.
December 1983	*Power Planning in Kentucky: Assessing Issues and Choices. Long Range Forecasts for Kentucky and its Six Major Utilities.* ESRG Study No. 83-51/TR I. Project manager.
July 1983	*Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings.* ESRG Study No. 83-14/S. Co-author.
October 1982	*The Economics of Closing the Indian Point Nuclear Power Plants.* ESRG Study No. 82-40. Principal investigator.
October 1982	Final Report of the Kentucky Public Service Commission. ESRG Study No. 82-45. Co-author.
August 1982	*Nuclear Capacity Factors: The Effects of Aging and Salt Water Cooling.* A Report on Research in Progress. ESRG Study No. 82-81. Co-author.
August 1982	*The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee.* ESRG Study No. 82-91. Co-author.
April 1982	*A Power Supply and Financial Analysis of the Seabrook Nuclear Station as a Generation Option for the Maine Public Service Company.* ESRG Study No. 81-61. Principal investigator.
January 1982	*Guidelines for Designing Rates for Sales to Qualifying Facilities Under Section 210 of the Public Utilities Regulatory Policies Act.* ESRG Study No. 81-32. Co-author.

July 1981	*Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern System.* ESRG Study No. 80-63. Co-author.
June 1981	*An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill.* A Report to: Robert M. Herzog, Director, New York City Energy Office and Allen G. Schwartz, Corporation Counsel for the City of New York. ESRG Study No. 81-21. Co-author.
October 1980	*The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning.* ESRG Study No. 80-12. A Report to the U.S. Department of Energy. Co-author.
September 1980	*Reducing New England's Oil Dependence Through Conservation and Alternative Energy.* ESRG Study No. 79-29. A Report to the U.S. General Accounting Office. Co-author.
July 1980	*Preliminary Economic and Need Analysis of the Proposed Brumley Gap Pumped Storage Facility for the AEP System.* ESRG Study No. 80-08/P. Principal investigator.
July 1980	*The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance.* ESRG Study No. 80-09. A Report to the Connecticut Power Facility Evaluation Council. Co-author.
November 1979	*South Carolina Electric Demand Curtailment Planning.* A Report to the South Carolina Office of Energy Resources. Principal investigator.
May 1979	*Demand Curtailment Planning: Methodology.* ESRG Study No. 78-18. Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study. Principal investigator.
May 1979	*Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model.* ESRG Study No. 79-06. A Report to the New England Conference of Public Utility Commissioners. Co-principal investigator.
October 1978	*The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993.* ESRG Study No. 78-16. Co-author.
November 1977	*Profile of Targets for the Energy Advisory Service to Industry.* ESRG Study No. 77-09. A Report to the New York State Energy Office. Co-Author.

October 1977	*The Effect on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.
July 1977	*The Effects on Air and Water Emissions of Energy Conservation in Industry.* ESRG Study No. 77-04. Co-author.
June 1977	*Toward an Energy Plan for New York.* ESRG Study No. 77-03. A Report to the Legislative Commission on Energy Systems. Co-author.
April 1977	*Assessing Demand, Alternative Operating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities.* ESRG Report No. 77-01. Co-author.

Other Publications

1992	"Bill Indexing," chapter in: *Regulatory Incentives for Demand Side Management*, edited by S. Nadel, et al. Published by ACEEE/NYSERDA. With David Moskovitz.
March 1978	*The Use of the Pulp and Paper Industry Process Model for R&D Decision Making.* Brookhaven National Laboratory Report No. BNL 24134. Co-author.
1976	"A Non-Linear Model for the Linewidth, Intensity, and Coherence of Astrophysical Masers," *Astrophysical Journal* vol. 190.

Papers and Presentations

1997	"How Do You Compute Stranded Costs?" A talk to ELCON. Washington, DC. October 30.
1997	"An Overview of Key Issues in Electric Industry Restructuring," presented to the Colorado Office of Consumer Counsel. June 26. Co-author.
1997	"Letting Retail Competition Succeed," presented at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.
1997	"A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," distributed at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.
1997	"A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Panelist.
May 1997	"Market Power, Mergers, and Deregulation: A Critique of FERC's New Merger Guidelines," The National Regulatory Research Institute *Quarterly Bulletin.*
April 1997	"A Whitepaper On Stranded Costs and Market Structures in the U.S. Electricity Industry," prepared for: The American Association of Retired Persons. Tellus No. 97-009. Draft.
1997	"A Point/Counterpoint Analysis of Major Restructuring Issues." Co-author.
June 1996	"Leveraging" - The Key to the Exercise of Market Power in a Poolco. NARUC and NASUCA Summer Meetings. Co-author.
September 1995	"The Status of Regulatory Policy Affecting the Restructuring of the Electric Utilities Industry." Presentation to: Wheelabrator Technologies, Inc.
August 1995	Presentation to Maine Public Service Company on Behalf of Wheelabrator Sherman to explain Tellus' Calculation of Estimates of Total Avoided Costs for Wheelabrator Sherman Power through 2015. Co-author.
November 1994	"Nine Fallacies in Computing Avoided Costs." Distributed at: The Annual NARUC/NASUCA Conference, Reno, NV. Co-author.

September 1994	"Apples and Oranges: Using Multi-Attribute Analysis in a Collaborative Process to Address Value Conflicts in Electric Facility Siting." Presented at: Ninth National Association of Regulatory Utility Commissioners (NARUC) Biennial Regulatory Information Conference, Columbus, Ohio, September 8. Co-author.
1993	"How Should Electric Utilities Allocate Their Free EPA-Granted Allowances Among Retail and Wholesale Customers? An Unresolved Issue of Clean Air Act Compliance. Prepared for distribution at: The NARUC/NASUCA 1993 Annual Meetings, New York, NY. November 14. Co-author.
February 1993	"Integrated Resource Planning and Clean Air Act Compliance: Elements of Consistency." Prepared for Distribution at: The NARUC Energy Conservation Committee 1993 Winter Meeting, Washington, DC. Co-author.
February 1991	"The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators," for distribution at the NARUC Conservation Committee, 1991 Winter Meeting, Washington, D.C. Co-author.
February 1991	"Sustainable Development and the Future of Electric Utilities," for the Energy Conservation Coalition Electric Utility Industry Vision Paper Project, Washington, DC.
September 1989	"Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C.
October 1988	"Ratemaking and Conservation: The Tune Should Fit the Dance," distributed at the NARUC Committee on Energy Conservation Meeting, San Francisco. October 30.
September 1987	"Electric Utility System Reliability and Reserves" (ESRG Paper). Co-author.
September 1986	"Risk Sharing and the 'Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). Co-author.
September 1986	"Risk Sharing, Excess Capacity, and the "Used and Useful" Criterion." Presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio.
July 24-28 1978	"Energy Use Modelling of the Iron and Steel Industry," Summer Computer Simulation Conference.
Nov. 12 1977	"Energy Conservation in Industry," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991. Term extended through June 1992.

Invited Speaker

March 1997	"Evaluating the Competitive Effect of Electric and Gas Utility Mergers Under Retail Competition." Panel - "Merger and Acquisitions: Implications of the Convergence of Electric and Gas Industries," *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, New Mexico State University, Santa Fe, NM. March 11.
November 1996	"NASUCA's Filing on the CRT NOPR at FERC," NASUCA Annual Conference.
June 1996	"Independent System Operators," NASUCA meeting, Chicago, IL.
November 1995	"Preserving Environmental Quality Under Electric Restructuring," NARUC Energy Conservation Committee meeting, New Orleans, LA.
November 1994	"Electricity Transmission Pricing," presented at NARUC Committee on Energy Conservation, Annual Meeting, Reno, NV. Co-author.
September 1994	Sixth Natural Gas Industry Forum, Quebec City. September 25-28.
June 1993	The National Energy Summit, in conjunction with the Multi-Media Energy Education Project of the Jefferson Energy Foundation - "Balancing Energy-Environment-Economy (E^3)", Washington, DC. Panelist.
September 1992	"Natural Gas Planning: An IRP Case Study." Presented at: The NARUC Conference on Integrated Resource Planning, Burlington, Vermont, September 13-16, 1992. Co-author.
September 1992	Fourth Natural Gas Industry Forum, Montreal.
March 1992	American Gas Association Long Range Forecasting for Integrated Resource Planning Seminar - "How Externalities and Supply Costs Affect IRP".
December 1991	Edison Electric Institute -- Strategic Planning Committee - "Incorporating Environmental Externalities into Integrated Resource Planning".

November 1990	NARUC Energy Conservation Committee Meeting, Orlando, Florida - "Rate Impacts of Demand-Side Management Programs".
November 1990	NARUC and NASUCA Joint Annual Meeting, Orlando, Florida - "Environmental Externalities and Integrated Resource Planning".

Awards and Honors

1968-1974	Faculty Fellowship, Physics Department Columbia University.
1966-1970	New York State Regents Fellowship.
1967-1968	Adam Leroy Jones Fellow in Philosophy, Columbia University.

12/97

Summary of Stranded Costs Estimates

Net Present Value of Stranded Costs (1996-2010)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	836	1198	42
High Market Price	411	1051	-440
Low Market Price	1211	1345	526

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2012)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	102	779	-834
High Market Price	-417	599	-1433
Low Market Price	559	959	-233

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2020)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	-838	513	-3009
High Market Price	-1578	257	-3927
Low Market Price	-186	770	-2090

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Cost Components of a Retail Generation Services Adder[1]
(mills per kWh)
Arizina Public Service Company (APS) & Tucson Electric Power Company (TEP)

Sources	Cost Component	Small Customers[2] - low case -	Small Customers[2] - high case -	Large Customers - low case -	Large Customers - high case -
1	Generation-related customer services	1.1	2.2	0.5	1.0
2	Other ancillary services not in current A&G	0.0	1.0	0.0	1.0
3	Generation-related A&G	5.0	5.0	5.0	5.0
4	Marketing and advertising	1.1	2.2	0.5	1.0
5	Subtotal	7.2	10.4	6.0	8.0
6	Profit	0.7	1.0	0.3	0.4
7	Income tax	0.3	0.4	0.1	0.1
8	Total	8.2	11.8	6.4	8.5

Weighted Average Retail Generation Services Adder Across Customer Classes
APS & TEP-- FERC Form 1 Data

1996 Sales	Small Customers		Large Customers	
Residential Sales (MWH)		10,057,722		0
Commercial Sales (MWH)		9,540,588		0
Industrial Sales (MWH)		0		6,406,035
Total Sales to Ultimate Customers (MWH)		19,598,310		6,406,035
	- low case -	- high case -	- low case -	- high case -
Weighted Average Adder	7.7	11.0	7.7	11.0

Footnotes:
1 These retail adders are not intended to be estimates of appropriate "generation credits" for the purpose of stimulating competition in a pilot program.
2 Assumes a consumption of 917 kWh per month, average over APS and TEP small customers.

Sources
1 Billing and collection services, customer inquiries, etc.
2 Refer to Exhibit___(RAR-2) for a listing of these ancillary services.
3 APS: actual cost embedded in its average retail rate.
4 N.H. PUC set 3.7 mills per kWh in the N.H. pilots, based on expenditures of $44 per small customer (500 kWh per month) over two years.
5 Subtotal of lines 1-4
6 Profit = 10% of retail adder
7 Income tax = 35% of profit
8 Total of lines 5-7

Table 3b: Projecting Future Costs for Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.37	1.37	18,753	256.0
1998	1.08	1.08	19,255	208.6
1999	0.78	0.78	19,523	152.1
2000	0.45	0.45	19,979	90.3
2001	0.32	0.32	19,968	63.3
2002	0.18	0.18	20,269	36.2
2003	0.04	0.04	20,911	7.5
2004	(0.11)	(0.11)	21,517	(23.9)
2005	(0.21)	(0.21)	22,110	(46.9)
2006	(0.32)	(0.32)	22,563	(71.5)
2007	(0.43)	(0.43)	23,024	(98.1)
2008	(0.54)	(0.54)	23,495	(126.7)
2009	(0.66)	(0.66)	23,975	(157.5)
2010	(0.78)	(0.78)	24,466	(190.6)
2011	(0.91)	(0.91)	24,966	(226.1)
2012	(1.04)	(1.04)	25,476	(264.2)
2013	(1.17)	(1.17)	25,997	(305.1)
2014	(1.31)	(1.31)	26,529	(348.8)
2015	(1.46)	(1.46)	27,072	(395.7)
2016	(1.61)	(1.61)	27,625	(445.8)
2017	(1.77)	(1.77)	28,190	(499.4)
2018	(1.93)	(1.93)	28,767	(556.6)
2019	(2.10)	(2.10)	29,355	(617.7)
2020	(2.28)	(2.28)	29,955	(682.9)

Net Present Value of Stranded Costs (1996-2010):		**$726.0**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1996-2010) (1998$):		**$836.3**
Net Present Value of Stranded Costs (1998-2012):		**($8.1)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2012) (1998$):		**$102.2**
Net Present Value of Stranded Costs (1998-2020):		**($947.9)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2020) (1998$):		**($837.6)**
Assumed utility nominal discount rate		**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.66	5.02	0.00
1998	3.94	5.02	0.00
1999	4.24	5.02	0.00
2000	4.57	5.02	0.00
2001	4.70	5.02	0.00
2002	4.84	5.02	0.00
2003	4.99	5.02	0.00
2004	5.13	5.02	0.00
2005	5.28	5.07	0.00
2006	5.44	5.12	0.00
2007	5.60	5.17	0.00
2008	5.77	5.23	0.00
2009	5.93	5.28	0.00
2010	6.11	5.33	0.00
2011	6.29	5.38	0.00
2012	6.48	5.44	0.00
2013	6.67	5.49	0.00
2014	6.86	5.55	0.00
2015	7.06	5.60	0.00
2016	7.27	5.66	0.00
2017	7.49	5.72	0.00
2018	7.71	5.77	0.00
2019	7.93	5.83	0.00
2020	8.17	5.89	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Arizona Public Service Company
(thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$508,476	$508,476			
O&M Minus Fuel	$416,344	$297,256			
Fuel	$211,220	$211,220			
Transmission	$14,067		$14,067		
Distribution	$50,207			$50,207	
Customer/Sales	$54,814				$54,814
Subtotal	$627,564	$508,476	$14,067	$50,207	$54,814
A&G[1]	$133,222	$ 95,116	$ 4,501	$ 16,065	$ 17,539
Total	$760,786	$603,592	$18,568	$66,272	$72,353
Plant Related Costs:					
Depreciation and Amort.	$237,555	$130,281	$29,423	$77,852	$0
Net Interest	$1,077	$551	$126	$401	$0
Net Income	$364,223	$186,122	$42,446	$135,656	$0
Income Taxes[2]	$178,514	$91,222	$20,804	$66,488	$0
Other Taxes[3]	$68,023	$34,761	$7,927	$25,335	$0
Residual[4]	$55,014	$28,113	$6,411	$20,490	$0
Total	$904,406	$471,049	$107,136	$326,221	$0
Total Operating Revenues[5]	$1,665,192	$1,074,641	$125,704	$392,493	$72,353
less Wholesale Revenues	($133,416)	($119,445)	($13,972)	$0	$0
Total Retail Revenues	$1,531,775	$955,196	$111,732	$392,493	$72,353
Total Retail Sales (MWH)	19,020,696				
Average Retail Rate (cents/kWh)	**8.05**	**5.02**	**0.59**	**2.06**	**0.38**

Footnotes:

[1] A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 71.4%, 3.4%, 12.1%, and 13.2%.

[2] Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

[3] Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

[4] Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

[5] Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 $/kW	0.84 c/kWh
Fixed O&M	11.7 $/kW-yr	0.24 c/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 c/kWh	1.72 c/kWh
	Sum of Levelized Costs:	*2.82 c/kWh*
	Levelized Capacity Costs:	*53.4 $/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 $/kW	7.04 ¢/kWh
Fixed O&M	9.4 $/kW-yr	2.21 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.16 c/kWh
	Sum of Levelized Costs:	*12.42 c/kWh*
	Levelized Capacity Costs:	*39.3 $/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		98.1%
Percent of CT energy in Market Price		1.9%
Average Price of CC/CT mix		**3.00 ¢/kWh**
T&D Line Loss Adjustment	7%	0.21 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge ($/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**2.36 ¢/kWh**
T&D Line Loss Adjustment	7%	**0.16 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**3.39 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):		User-Input			
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Source: Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer, in Docket No. 16705, Texas Direct Testimony and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Tellus Institute, Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	54%
Max. Annual Load (MW)	4616
Min. Monthly Peak (MW)	2484
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	2023
Max. Load + Reserve Margin (MW)	5308
Cut-off point:	11.0%
Load at above Cut-off (MW)	4331
Total Energy under Load Curve (MWh)	21,865,083
Energy Supplied by CTs (MWh)	415,437
Energy Supplied by CCs (MWh)	21,449,646
Percentage of Energy Supplied by CTs	1.9%
Percentage of Energy Supplied by CCs	98.1%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	1,755,196	121,658	1,633,538	3,134
Feb	1,538,583	93,484	1,445,099	3,027
Mar	1,578,178	81,408	1,496,770	2,703
Apr	1,606,380	70,048	1,536,332	3,223
May	1,888,666	52,951	1,835,715	3,576
Jun	2,176,835	72,505	2,104,330	4,113
Jul	2,546,161	61,708	2,484,453	4,616
Aug	2,492,746	32,371	2,460,375	4,491
Sep	2,070,813	150,700	1,920,113	3,953
Oct	2,062,028	284,609	1,777,419	3,662
Nov	1,901,166	424,258	1,476,908	2,484
Dec	2,147,940	453,909	1,694,031	3,354
TOTAL	23,764,692	1,899,609	21,865,083	4,616

Utility FERC Form 1 Data

Average Wholesale Market Price of Electricity Based on CC/CT Method	**30.04**	**$/MWh**
	3.00	**c/kWh**
T&D Line Loss Adjustment	**0.21**	**c/kWh**
Order 888 Ancillary Services	**0.10**	**c/kWh**
Retailing A&G Adjustment	**0.50**	**c/kWh**
Other Retailing Costs Adjstmt	**0.27**	**c/kWh**

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	**NA**	**$/MW**
Energy Charge	**NA**	**c/kWh**
User-Input Retail Market Price:	**3.39**	**c/kWh**

CC-CT Market Price Worksheet for: Arizona Public Service Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	1,755,196	121,658	1,633,538	3,134			
Feb	1,538,583	93,484	1,445,099	3,027			
Mar	1,578,178	81,408	1,496,770	2,703			
Apr	1,606,380	70,048	1,536,332	3,223			
May	1,888,666	52,951	1,835,715	3,576			
Jun	2,176,835	72,505	2,104,330	4,113			
Jul	2,546,161	61,708	2,484,453	4,616			
Aug	2,492,746	32,371	2,460,375	4,491			
Sep	2,070,813	150,700	1,920,113	3,953			
Oct	2,062,028	284,609	1,777,419	3,662			
Nov	1,901,166	424,258	1,476,908	2,484	2484	81%	2,023
Dec	2,147,940	453,909	1,694,031	3,354			
TOTAL	23,764,692	1,899,609	21,865,083	4,616	2,484	0.81	2,023

LOAD FACTOR	54%
Max. Annual Load (MW)	4,616
Min. Monthly Peak (MW)	2,484
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	2,023
Max. Load + Reserve Margin (MW)	5,308
Cut-off point:	11%
Load at above Cut-off (MW)	4,331
Total Energy under Load Curve (MWh)	21,865,083
Energy Supplied by CTs (MWh)	415,437
Energy Supplied by CCs (MWh)	21,449,646
check	0

ratio between total energy under load curve and total monthly energy: 0.92

Ratio of energy supplied by CTs	1.9%
Ratio of energy supplied by CCs	98.1%

						$ 28.21	MWh
CC							
Capital Cost	41.67	$/kW times	4,331	MW	equals	180,465,659	dollars
Fixed O&M	11.70	$/kW times	4,331	MW	equals	50,670,217	dollars
Var O&M	0.20	mills/kWh times	21,449,646	MWh	equals	4,289,929	dollars
Fuel	1.72	cents/kWh times	21,449,646	MWh	equals	369,748,232	dollars
CT						$ 124.19	MWh
Capital Cost	29.92	$/kW times	978	MW	equals	29,250,158	dollars
Fixed O&M	9.40	$/kW times	978	MW	equals	9,189,555	dollars
Var O&M	0.10	mills/kWh times	415,437	MWh	equals	41,544	dollars
Fuel	3.16	cents/kWh times	415,437	MWh	equals	13,110,652	dollars
					TOTAL	656,765,946	dollars
					Tot Energy in real LDC	21,865,083	MWh

OUTPUT

Average Market Price of Electricity - 1996

30.04	$/MWh
3.00	c/kWh

Table 3b: Projecting Future Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.32	1.32	18,753	247.1
1998	0.98	0.98	19,255	188.6
1999	0.61	0.61	19,523	119.2
2000	0.21	0.21	19,979	41.5
2001	0.07	0.07	19,968	13.2
2002	(0.08)	(0.08)	20,269	(16.2)
2003	(0.23)	(0.23)	20,911	(48.2)
2004	(0.39)	(0.39)	21,517	(82.9)
2005	(0.49)	(0.49)	22,110	(109.3)
2006	(0.61)	(0.61)	22,563	(137.1)
2007	(0.73)	(0.73)	23,024	(166.9)
2008	(0.85)	(0.85)	23,495	(199.0)
2009	(0.97)	(0.97)	23,975	(233.5)
2010	(1.11)	(1.11)	24,466	(270.4)
2011	(1.24)	(1.24)	24,966	(309.9)
2012	(1.38)	(1.38)	25,476	(352.3)
2013	(1.53)	(1.53)	25,997	(397.6)
2014	(1.68)	(1.68)	26,529	(446.0)
2015	(1.84)	(1.84)	27,072	(497.8)
2016	(2.00)	(2.00)	27,625	(553.1)
2017	(2.17)	(2.17)	28,190	(612.1)
2018	(2.35)	(2.35)	28,767	(675.0)
2019	(2.53)	(2.53)	29,355	(742.1)
2020	(2.72)	(2.72)	29,955	(813.6)

Net Present Value of Stranded Costs (1996-2010):		**$300.3**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1996-2010) (1998$):		**$410.6**
Net Present Value of Stranded Costs (1998-2012):		**($527.1)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2012) (1998$):		**($416.7)**
Net Present Value of Stranded Costs (1998-2020):		**($1,688.4)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2020) (1998$):		**($1,578.0)**
Assumed utility nominal discount rate		**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

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Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: *Scenario Assumptions*
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.70	5.02	0.00
1998	4.04	5.02	0.00
1999	4.41	5.02	0.00
2000	4.81	5.02	0.00
2001	4.96	5.02	0.00
2002	5.10	5.02	0.00
2003	5.25	5.02	0.00
2004	5.41	5.02	0.00
2005	5.57	5.07	0.00
2006	5.73	5.12	0.00
2007	5.90	5.17	0.00
2008	6.07	5.23	0.00
2009	6.25	5.28	0.00
2010	6.44	5.33	0.00
2011	6.63	5.38	0.00
2012	6.82	5.44	0.00
2013	7.02	5.49	0.00
2014	7.23	5.55	0.00
2015	7.44	5.60	0.00
2016	7.66	5.66	0.00
2017	7.89	5.72	0.00
2018	8.12	5.77	0.00
2019	8.36	5.83	0.00
2020	8.60	5.89	0.00

[1] All costs are in nominal dollars.

**Table 3b: Projecting Future Costs for
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills**

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.63	1.63	18,428	299.9
1997	1.41	1.41	18,753	264.2
1998	1.18	1.18	19,255	226.6
1999	0.93	0.93	19,523	181.4
2000	0.67	0.67	19,979	133.1
2001	0.54	0.54	19,968	107.4
2002	0.41	0.41	20,269	82.3
2003	0.27	0.27	20,911	56.4
2004	0.13	0.13	21,517	27.9
2005	0.04	0.04	22,110	7.9
2006	(0.06)	(0.06)	22,563	(13.9)
2007	(0.16)	(0.16)	23,024	(37.6)
2008	(0.27)	(0.27)	23,495	(63.1)
2009	(0.38)	(0.38)	23,975	(90.7)
2010	(0.49)	(0.49)	24,466	(120.4)
2011	(0.61)	(0.61)	24,966	(152.4)
2012	(0.73)	(0.73)	25,476	(186.8)
2013	(0.86)	(0.86)	25,997	(223.8)
2014	(0.99)	(0.99)	26,529	(263.4)
2015	(1.13)	(1.13)	27,072	(305.9)
2016	(1.27)	(1.27)	27,625	(351.5)
2017	(1.42)	(1.42)	28,190	(400.3)
2018	(1.57)	(1.57)	28,767	(452.6)
2019	(1.73)	(1.73)	29,355	(508.4)
2020	(1.90)	(1.90)	29,955	(568.1)

Net Present Value of Stranded Costs (1996-2010):		**$1,101.0**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1996-2010) (1998$):		**$1,211.3**
Net Present Value of Stranded Costs (1998-2012):		**$448.6**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2012) (1998$):		**$558.9**
Net Present Value of Stranded Costs (1998-2020):		**($296.6)**
Generation-Related Assets Not in Rates:	**$**	**110.3**
Total NPV of Stranded Costs (1998-2020) (1998$):		**($186.3)**
Assumed utility nominal discount rate		**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 2.0%

Table 3a: Projections of Stranded Costs[1]
Arizona Public Service Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.39	5.02	0.00
1997	3.61	5.02	0.00
1998	3.85	5.02	0.00
1999	4.09	5.02	0.00
2000	4.36	5.02	0.00
2001	4.48	5.02	0.00
2002	4.62	5.02	0.00
2003	4.75	5.02	0.00
2004	4.89	5.02	0.00
2005	5.04	5.07	0.00
2006	5.18	5.12	0.00
2007	5.34	5.17	0.00
2008	5.49	5.23	0.00
2009	5.66	5.28	0.00
2010	5.82	5.33	0.00
2011	5.99	5.38	0.00
2012	6.17	5.44	0.00
2013	6.35	5.49	0.00
2014	6.54	5.55	0.00
2015	6.73	5.60	0.00
2016	6.93	5.66	0.00
2017	7.14	5.72	0.00
2018	7.35	5.77	0.00
2019	7.56	5.83	0.00
2020	7.78	5.89	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.24	1.24	18,856	233.4
1997	1.02	1.02	19,627	200.3
1998	0.79	0.79	20,430	161.4
1999	0.55	0.55	21,266	116.0
2000	0.29	0.29	22,135	63.4
2001	0.15	0.15	23,041	34.9
2002	0.01	0.01	23,983	2.9
2003	(0.13)	(0.13)	24,964	(32.7)
2004	(0.28)	(0.28)	25,985	(72.4)
2005	(0.43)	(0.43)	27,048	(116.4)
2006	(0.59)	(0.59)	28,154	(165.2)
2007	(0.75)	(0.75)	29,305	(219.2)
2008	(0.91)	(0.91)	30,504	(278.8)
2009	(1.08)	(1.08)	31,752	(344.4)
2010	(1.26)	(1.26)	33,050	(416.6)
2011	(1.44)	(1.44)	34,402	(495.9)
2012	(1.63)	(1.63)	35,809	(582.9)
2013	(1.82)	(1.82)	37,274	(678.3)
2014	(2.02)	(2.02)	38,798	(782.7)
2015	(2.22)	(2.22)	40,385	(896.8)
2016	(2.43)	(2.43)	42,037	(1,021.6)
2017	(2.65)	(2.65)	43,756	(1,157.7)
2018	(2.87)	(2.87)	45,546	(1,306.2)
2019	(3.10)	(3.10)	47,409	(1,468.1)
2020	(3.33)	(3.33)	49,348	(1,644.3)

Net Present Value of Stranded Costs (1996-2010) (1998$):	**$42.0**
Net Present Value of Stranded Costs (1998-2012) (1998$):	**($833.7)**
Net Present Value of Stranded Costs (1998-2020) (1998$):	**($3,009.1)**
PV of Generation-Related Assets Not in Rates:	**$0**
Total Net Present Value of Stranded Costs (1998-2020) (1998$):	**($3,009.1)**
Assumed utility nominal discount rate	**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs[1]
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on: User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates: See Table 4: Scenario Assumptions

Year when excess capacity ends: 2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.83	4.85	0.00
1998	4.06	4.85	0.00
1999	4.30	4.85	0.00
2000	4.56	4.85	0.00
2001	4.70	4.85	0.00
2002	4.84	4.85	0.00
2003	4.98	4.85	0.00
2004	5.13	4.85	0.00
2005	5.28	4.85	0.00
2006	5.44	4.85	0.00
2007	5.60	4.85	0.00
2008	5.76	4.85	0.00
2009	5.93	4.85	0.00
2010	6.11	4.85	0.00
2011	6.29	4.85	0.00
2012	6.48	4.85	0.00
2013	6.67	4.85	0.00
2014	6.87	4.85	0.00
2015	7.07	4.85	0.00
2016	7.28	4.85	0.00
2017	7.49	4.85	0.00
2018	7.72	4.85	0.00
2019	7.95	4.85	0.00
2020	8.18	4.85	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Salt River Project Agricultural Improvement & Power District
(thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$642,208	$642,208			
O&M Minus Fuel	$430.824	$329.164			
Fuel	$313,044	$313,044			
Transmission	$14,836		$14,836		
Distribution	$47,360			$47,360	
Customer/Sales	$39,464				$39,464
Subtotal	$743,868	$642,208	$14,836	$47,360	$39,464
A&G[1]	$123,651	$94,474	$4,258	$13,593	$11,326
Total	$867,519	$736,682	$19,094	$60,953	$50,790
Plant Related Costs:					
Depreciation and Amort.	$232,486	$145,859	$28,909	$57,718	$0
Net Interest	$205,729	$123,280	$26,274	$56,175	$0
Net Income	$57,653	$34,547	$7,363	$15,742	$0
Income Taxes[2]	$0	$0	$0	$0	$0
Other Taxes[3]	$5,383	$3,226	$687	$1,470	$0
Residual[4]	($0)	($0)	($0)	($0)	$0
Total	$501,250	$306,911	$63,234	$131,105	$0
Total Operating Revenues[5]	$1,368,769	$1,043,593	$82,328	$192,058	$50,790
less Wholesale Revenues	($139,584)	($129,377)	($10,206)	$0	$0
Total Retail Revenues	$1,229,185	$914,216	$72,121	$192,058	$50,790
Total Retail Sales (MWH)	18,856,006				
Average Retail Rate (cents/kWh)	**6.52**	**4.85**	**0.38**	**1.02**	**0.27**

Footnotes:

1 A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 76.4%, 3.4%, 11.0%, and 9.2%.

2 Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

3 Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

4 Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

5 Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:			
	Adjusted Retail Market Price *		**4.56 ¢/kWh**
	Year Excess Capacity Ends		**2000**
(2) Using Capacity Charge and Energy Charge:			
	Capacity Charge ($/kW-yr):	**NA**	
	Energy Charge (¢/kWh):	**NA**	
	Average Market Price for Electricity:		**none ¢/kWh**
(3) Using an Exogenous Value:			
	User-Input Wholesale Market Price for Electricity		**2.59 ¢/kWh**
	T&D Line Loss Adjustment	6%	**0.15 ¢/kWh**
	Order 888 Ancillary Services		**0.10 ¢/kWh**
	Retailing A&G Adjustment		**0.50 ¢/kWh**
	Other Retailing Costs Adjustment		**0.27 ¢/kWh**
	User-Input Retail Market Price for Electricity		**3.61 ¢/kWh**

***Market price for year 2000 and after based on average of CC/CT mix for two Arizona Utilities**

Table 4
Assumptions Used in Estimating Stranded Costs for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):		*User-Input*			
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Schnitzer and EIA Annual Energy Outlook 1997

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	-	-	-	-
Feb	-	-	-	-
Mar	-	-	-	-
Apr	-	-	-	-
May	-	-	-	-
Jun	-	-	-	-
Jul	-	-	-	-
Aug	-	-	-	-
Sep	-	-	-	-
Oct	-	-	-	-
Nov	-	-	-	-
Dec	-	-	-	-
TOTAL	26,178,809	5,687,218	20,491,591	-

Utility FERC Form 1 Data

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	3.61	c/kWh

Table 3b: Projecting Future Costs for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.24	1.24	18,856	233.4
1997	0.97	0.97	19,627	191.0
1998	0.69	0.69	20,430	140.9
1999	0.39	0.39	21,266	81.9
2000	0.06	0.06	22,135	12.9
2001	(0.08)	(0.08)	23,041	(19.2)
2002	(0.23)	(0.23)	23,983	(55.1)
2003	(0.38)	(0.38)	24,964	(94.9)
2004	(0.53)	(0.53)	25,985	(139.0)
2005	(0.69)	(0.69)	27,048	(187.8)
2006	(0.86)	(0.86)	28,154	(241.8)
2007	(1.03)	(1.03)	29,305	(301.2)
2008	(1.20)	(1.20)	30,504	(366.6)
2009	(1.38)	(1.38)	31,752	(438.6)
2010	(1.57)	(1.57)	33,050	(517.5)
2011	(1.76)	(1.76)	34,402	(604.1)
2012	(1.95)	(1.95)	35,809	(698.8)
2013	(2.15)	(2.15)	37,274	(802.5)
2014	(2.36)	(2.36)	38,798	(915.9)
2015	(2.57)	(2.57)	40,385	(1,039.6)
2016	(2.79)	(2.79)	42,037	(1,174.6)
2017	(3.02)	(3.02)	43,756	(1,321.7)
2018	(3.25)	(3.25)	45,546	(1,482.0)
2019	(3.49)	(3.49)	47,409	(1,656.4)
2020	(3.74)	(3.74)	49,348	(1,846.2)

Net Present Value of Stranded Costs (1996-2010) (1998$):	**($440.3)**
Net Present Value of Stranded Costs (1998-2012) (1998$):	**($1,433.3)**
Net Present Value of Stranded Costs (1998-2020) (1998$):	**($3,927.3)**
PV of Generation-Related Assets Not in Rates:	**$0**
Total Net Present Value of Stranded Costs (1998-2020) (1998$):	**($3,927.3)**
Assumed utility nominal discount rate	**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs[1]

Salt River Project Agricultural Improvement & Power District

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.88	4.85	0.00
1998	4.16	4.85	0.00
1999	4.46	4.85	0.00
2000	4.79	4.85	0.00
2001	4.93	4.85	0.00
2002	5.08	4.85	0.00
2003	5.23	4.85	0.00
2004	5.38	4.85	0.00
2005	5.54	4.85	0.00
2006	5.71	4.85	0.00
2007	5.88	4.85	0.00
2008	6.05	4.85	0.00
2009	6.23	4.85	0.00
2010	6.41	4.85	0.00
2011	6.60	4.85	0.00
2012	6.80	4.85	0.00
2013	7.00	4.85	0.00
2014	7.21	4.85	0.00
2015	7.42	4.85	0.00
2016	7.64	4.85	0.00
2017	7.87	4.85	0.00
2018	8.10	4.85	0.00
2019	8.34	4.85	0.00
2020	8.59	4.85	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	1.24	1.24	18,856	233.4
1997	1.07	1.07	19,627	209.8
1998	0.89	0.89	20,430	182.4
1999	0.71	0.71	21,266	150.6
2000	0.51	0.51	22,135	113.9
2001	0.39	0.39	23,041	89.0
2002	0.25	0.25	23,983	60.9
2003	0.12	0.12	24,964	29.4
2004	(0.02)	(0.02)	25,985	(5.8)
2005	(0.17)	(0.17)	27,048	(45.1)
2006	(0.32)	(0.32)	28,154	(88.7)
2007	(0.47)	(0.47)	29,305	(137.2)
2008	(0.63)	(0.63)	30,504	(190.9)
2009	(0.79)	(0.79)	31,752	(250.2)
2010	(0.95)	(0.95)	33,050	(315.6)
2011	(1.13)	(1.13)	34,402	(387.7)
2012	(1.30)	(1.30)	35,809	(466.9)
2013	(1.49)	(1.49)	37,274	(554.0)
2014	(1.67)	(1.67)	38,798	(649.5)
2015	(1.87)	(1.87)	40,385	(754.1)
2016	(2.07)	(2.07)	42,037	(868.6)
2017	(2.27)	(2.27)	43,756	(993.8)
2018	(2.48)	(2.48)	45,546	(1,130.5)
2019	(2.70)	(2.70)	47,409	(1,279.7)
2020	(2.92)	(2.92)	49,348	(1,442.5)

Net Present Value of Stranded Costs (1996-2010) (1998$):	**$525.5**
Net Present Value of Stranded Costs (1998-2012) (1998$):	**($233.1)**
Net Present Value of Stranded Costs (1998-2020) (1998$):	**($2,090.1)**
PV of Generation-Related Assets Not in Rates:	**$0**
Total Net Present Value of Stranded Costs (1998-2020) (1998$):	**($2,090.1)**
Assumed utility nominal discount rate	**7.75%**

[1] System generation, excluding purchased power. Assumed escalation rate: 4.1%

Table 3a: Projections of Stranded Costs[1]
Salt River Project Agricultural Improvement & Power District
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on: User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends

Escalation Rates: See Table 4: Scenario Assumptions

Year when excess capacity ends: 2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	3.61	4.85	0.00
1997	3.78	4.85	0.00
1998	3.96	4.85	0.00
1999	4.14	4.85	0.00
2000	4.33	4.85	0.00
2001	4.46	4.85	0.00
2002	4.59	4.85	0.00
2003	4.73	4.85	0.00
2004	4.87	4.85	0.00
2005	5.01	4.85	0.00
2006	5.16	4.85	0.00
2007	5.32	4.85	0.00
2008	5.47	4.85	0.00
2009	5.64	4.85	0.00
2010	5.80	4.85	0.00
2011	5.98	4.85	0.00
2012	6.15	4.85	0.00
2013	6.33	4.85	0.00
2014	6.52	4.85	0.00
2015	6.72	4.85	0.00
2016	6.91	4.85	0.00
2017	7.12	4.85	0.00
2018	7.33	4.85	0.00
2019	7.55	4.85	0.00
2020	7.77	4.85	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.10	3.10	6,986	216.4
1998	2.65	2.65	7,122	188.5
1999	2.13	2.13	7,261	154.4
2000	1.53	1.53	7,403	113.3
2001	1.39	1.39	7,548	105.1
2002	1.25	1.25	7,695	96.4
2003	1.11	1.11	7,846	86.9
2004	0.96	0.96	7,999	76.6
2005	0.80	0.80	8,155	65.6
2006	0.65	0.65	8,315	53.7
2007	0.48	0.48	8,477	40.9
2008	0.31	0.31	8,643	27.2
2009	0.14	0.14	8,812	12.5
2010	(0.04)	(0.04)	8,984	(3.3)
2011	(0.22)	(0.22)	9,159	(20.2)
2012	(0.41)	(0.41)	9,338	(38.2)
2013	(0.60)	(0.60)	9,521	(57.5)
2014	(0.80)	(0.80)	9,707	(78.1)
2015	(1.01)	(1.01)	9,897	(100.0)
2016	(1.22)	(1.22)	10,090	(123.4)
2017	(1.44)	(1.44)	10,287	(148.3)
2018	(1.67)	(1.67)	10,488	(174.9)
2019	(1.90)	(1.90)	10,693	(203.1)
2020	(2.14)	(2.14)	10,902	(233.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,197.8**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$778.9**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$513.4**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$513.4**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.02	6.12	0.00
1998	3.47	6.12	0.00
1999	3.99	6.12	0.00
2000	4.59	6.12	0.00
2001	4.73	6.12	0.00
2002	4.87	6.12	0.00
2003	5.01	6.12	0.00
2004	5.16	6.12	0.00
2005	5.32	6.12	0.00
2006	5.48	6.12	0.00
2007	5.64	6.12	0.00
2008	5.81	6.12	0.00
2009	5.98	6.12	0.00
2010	6.16	6.12	0.00
2011	6.34	6.12	0.00
2012	6.53	6.12	0.00
2013	6.72	6.12	0.00
2014	6.93	6.12	0.00
2015	7.13	6.12	0.00
2016	7.34	6.12	0.00
2017	7.56	6.12	0.00
2018	7.79	6.12	0.00
2019	8.02	6.12	0.00
2020	8.26	6.12	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Tucson Electric Power Company
(thousand dollars)

Category	Total Cost	Cost Components Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$339,092	$339,092			
O&M Minus Fuel	$135,991	$135.991			
Fuel	$203,102	$203,102			
Transmission	$6,894		$6,894		
Distribution	$12,284			$12,284	
Customer/Sales	$14,501				$14,501
Subtotal	$372,771	$339,092	$6,894	$12,284	$14,501
A&G[1]	$59,943	$48,044	$2,436	$4,340	$5,123
Total	$432,714	$387,136	$9,330	$16,624	$19,624
Plant Related Costs:					
Depreciation and Amort.	$76,229	$38,188	$17,533	$20,508	$0
Net Interest	$103,096	$49,431	$23,867	$29,799	$0
Net Income	$11,982	$5,745	$2,774	$3,463	$0
Income Taxes[2]	$9,892	$4,743	$2,290	$2,859	$0
Other Taxes[3]	$37,604	$18,030	$8,705	$10,869	$0
Residual[4]	$21,514	$10,315	$4,980	$6,218	$0
Total	$260,317	$126,452	$60,149	$73,716	$0
Total Operating Revenues[5]	$693,031	$513,588	$69,479	$90,341	$19,624
less Wholesale Revenues	($106,945)	($94,201)	($12,744)	$0	$0
Total Retail Revenues	$586,087	$419,387	$56,735	$90,341	$19,624
Total Retail Sales (MWH)	6,851,706				
Average Retail Rate (cents/kWh)	**8.55**	**6.12**	**0.83**	**1.32**	**0.29**

Footnotes:

1 A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 80.2%, 4.1%, 7.2%, and 8.5%.
2 Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).
3 Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.
4 Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).
5 Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 $/kW	0.79 ¢/kWh
Fixed O&M	11.7 $/kW-yr	0.22 ¢/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.71 ¢/kWh
	Sum of Levelized Costs:	*2.74 ¢/kWh*
	Levelized Capacity Costs:	*53.4 $/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 $/kW	29.47 ¢/kWh
Fixed O&M	9.4 $/kW-yr	9.26 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.13 ¢/kWh
	Sum of Levelized Costs:	*41.86 ¢/kWh*
	Levelized Capacity Costs:	*39.3 $/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		99.6%
Percent of CT energy in Market Price		0.4%
Average Price of CC/CT mix		**2.91 ¢/kWh**
T&D Line Loss Adjustment	10%	0.30 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge ($/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**1.59 ¢/kWh**
T&D Line Loss Adjustment	10%	**0.17 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**2.63 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for Tucson Electric Power Company

Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):		User-Input			
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Souce: Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer, in Docket #16705, Direct Testimony on behalf of TX OPUC, and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Tellus Institute. Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	57%
Max. Annual Load (MW)	1619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1862
Cut-off point:	11.0%
Load at above Cut-off (MW)	1527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
Percentage of Energy Supplied by CTs	0.4%
Percentage of Energy Supplied by CCs	99.6%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	855,793	261,591	594,202	1,062
Feb	763,804	224,230	539,574	1,043
Mar	806,714	236,376	570,338	961
Apr	836,467	249,242	587,225	1,255
May	920,007	212,419	707,588	1,410
Jun	992,763	213,336	779,427	1,519
Jul	1,144,033	262,289	881,744	1,619
Aug	1,131,929	276,469	855,460	1,608
Sep	1,012,034	307,068	704,966	1,369
Oct	1,032,968	378,436	654,532	1,355
Nov	942,033	383,554	558,479	987
Dec	994,999	373,905	621,094	1,102
TOTAL	11,433,544	3,378,915	8,054,629	1,619

Utility FERC Form 1 Data

Average Wholesale Market Price		
of Electricity Based	29.09	$/MWh
on CC/CT Method	2.91	c/kWh
T&D Line Loss Adjustment	0.30	c/kWh
Order 888 Ancillary Services	0.10	c/kWh
Retailing A&G Adjustment	0.50	c/kWh
Other Retailing Costs Adjstmt	0.27	c/kWh

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	2.63	c/kWh

CC-CT Market Price Worksheet for: Tucson Electric Power Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	855,793	261,591	594,202	1,062			
Feb	763,804	224,230	539,574	1,043			
Mar	806,714	236,376	570,338	961	961	81%	781
Apr	836,467	249,242	587,225	1,255			
May	920,007	212,419	707,588	1,410			
Jun	992,763	213,336	779,427	1,519			
Jul	1,144,033	262,289	881,744	1,619			
Aug	1,131,929	276,469	855,460	1,608			
Sep	1,012,034	307,068	704,966	1,369			
Oct	1,032,968	378,436	654,532	1,355			
Nov	942,033	383,554	558,479	987			
Dec	994,999	373,905	621,094	1,102			
TOTAL	11,433,544	3,378,915	8,054,629	1,619	961	0.81	781

LOAD FACTOR	57%
Max. Annual Load (MW)	1,619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1,862
Cut-off point:	11%
Load at above Cut-off (MW)	1,527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
check	0

ratio between total energy under load curve and total monthly energy: 0.92

Ratio of energy supplied by CTs	0.4%
Ratio of energy supplied by CCs	99.6%

CC

Capital Cost	41.67	$/kW times	1,527	MW	equals	63,624,506	dollars	$ 27.43 MWh
Fixed O&M	11.70	$/kW times	1,527	MW	equals	17,864,161	dollars	
Var O&M	0.20	mills/kWh times	8,020,614	MWh	equals	1,604,123	dollars	
Fuel	1.71	cents/kWh times	8,020,614	MWh	equals	136,950,332	dollars	

CT

Capital Cost	29.92	$/kW times	335	MW	equals	10,023,160	dollars	$ 418.61 MWh
Fixed O&M	9.40	$/kW times	335	MW	equals	3,148,987	dollars	
Var O&M	0.10	mills/kWh times	34,015	MWh	equals	3,401	dollars	
Fuel	3.13	cents/kWh times	34,015	MWh	equals	1,063,294	dollars	
					TOTAL	234,281,965	dollars	
					Tot Energy in real LDC	8,054,629	MWh	

OUTPUT

Average Market Price of Electricity - 1996

29.09	$/MWh
2.91	c/kWh

**Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills**

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.06	3.06	6,986	213.8
1998	2.56	2.56	7,122	182.4
1999	1.98	1.98	7,261	143.6
2000	1.30	1.30	7,403	96.3
2001	1.16	1.16	7,548	87.3
2002	1.01	1.01	7,695	77.6
2003	0.86	0.86	7,846	67.2
2004	0.70	0.70	7,999	56.0
2005	0.54	0.54	8,155	43.9
2006	0.37	0.37	8,315	30.9
2007	0.20	0.20	8,477	17.0
2008	0.02	0.02	8,643	2.1
2009	(0.16)	(0.16)	8,812	(13.9)
2010	(0.34)	(0.34)	8,984	(31.0)
2011	(0.54)	(0.54)	9,159	(49.2)
2012	(0.74)	(0.74)	9,338	(68.7)
2013	(0.94)	(0.94)	9,521	(89.5)
2014	(1.15)	(1.15)	9,707	(111.7)
2015	(1.37)	(1.37)	9,897	(135.3)
2016	(1.59)	(1.59)	10,090	(160.5)
2017	(1.82)	(1.82)	10,287	(187.2)
2018	(2.06)	(2.06)	10,488	(215.7)
2019	(2.30)	(2.30)	10,693	(246.0)
2020	(2.55)	(2.55)	10,902	(278.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,050.9**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$599.1**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$257.2**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$257.2**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]

Tucson Electric Power Company

Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.06	6.12	0.00
1998	3.56	6.12	0.00
1999	4.14	6.12	0.00
2000	4.82	6.12	0.00
2001	4.96	6.12	0.00
2002	5.11	6.12	0.00
2003	5.26	6.12	0.00
2004	5.42	6.12	0.00
2005	5.58	6.12	0.00
2006	5.75	6.12	0.00
2007	5.92	6.12	0.00
2008	6.10	6.12	0.00
2009	6.28	6.12	0.00
2010	6.47	6.12	0.00
2011	6.66	6.12	0.00
2012	6.86	6.12	0.00
2013	7.06	6.12	0.00
2014	7.27	6.12	0.00
2015	7.49	6.12	0.00
2016	7.71	6.12	0.00
2017	7.94	6.12	0.00
2018	8.18	6.12	0.00
2019	8.42	6.12	0.00
2020	8.67	6.12	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.14	3.14	6,986	219.1
1998	2.73	2.73	7,122	194.7
1999	2.28	2.28	7,261	165.4
2000	1.76	1.76	7,403	130.3
2001	1.63	1.63	7,548	123.0
2002	1.50	1.50	7,695	115.1
2003	1.36	1.36	7,846	106.5
2004	1.22	1.22	7,999	97.3
2005	1.07	1.07	8,155	87.2
2006	0.92	0.92	8,315	76.4
2007	0.76	0.76	8,477	64.8
2008	0.60	0.60	8,643	52.3
2009	0.44	0.44	8,812	38.8
2010	0.27	0.27	8,984	24.3
2011	0.10	0.10	9,159	8.9
2012	(0.08)	(0.08)	9,338	(7.7)
2013	(0.27)	(0.27)	9,521	(25.5)
2014	(0.46)	(0.46)	9,707	(44.5)
2015	(0.65)	(0.65)	9,897	(64.7)
2016	(0.86)	(0.86)	10,090	(86.4)
2017	(1.06)	(1.06)	10,287	(109.4)
2018	(1.28)	(1.28)	10,488	(134.0)
2019	(1.50)	(1.50)	10,693	(160.2)
2020	(1.73)	(1.73)	10,902	(188.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,345.2**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$958.9**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$770.0**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$770.0**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	2.98	6.12	0.00
1998	3.39	6.12	0.00
1999	3.84	6.12	0.00
2000	4.36	6.12	0.00
2001	4.49	6.12	0.00
2002	4.63	6.12	0.00
2003	4.76	6.12	0.00
2004	4.91	6.12	0.00
2005	5.05	6.12	0.00
2006	5.20	6.12	0.00
2007	5.36	6.12	0.00
2008	5.52	6.12	0.00
2009	5.68	6.12	0.00
2010	5.85	6.12	0.00
2011	6.02	6.12	0.00
2012	6.20	6.12	0.00
2013	6.39	6.12	0.00
2014	6.58	6.12	0.00
2015	6.77	6.12	0.00
2016	6.98	6.12	0.00
2017	7.18	6.12	0.00
2018	7.40	6.12	0.00
2019	7.62	6.12	0.00
2020	7.85	6.12	0.00

[1] All costs are in nominal dollars.

Projected Prices of Natural Gas Used for Power Generation

Assumed inflation rate	3%

	EIA (Mountain) (1995$/Mmbtu) (1)	AZ projected 12% (2)		AZ projected ($1996/Mmbtu)
1995	1.69	$ 1.77	Actual	$ 1.82
1996	2.07	$ 3.03		$ 3.03
1997	1.83	$ 2.05		$ 2.11
1998	1.96	$ 2.20		$ 2.27
1999	2.01	$ 2.25		$ 2.32
2000	2.05	$ 2.29		$ 2.36
2001	2.07	$ 2.32		$ 2.39
2002	2.15	$ 2.41		$ 2.48
2003	2.24	$ 2.51		$ 2.59
2004	2.32	$ 2.60		$ 2.68
2005	2.35	$ 2.64		$ 2.72
2006	2.36	$ 2.65		$ 2.73
2007	2.36	$ 2.65		$ 2.73
2008	2.36	$ 2.65		$ 2.73
2009	2.35	$ 2.63		$ 2.71
2010	2.35	$ 2.63		$ 2.71
2011	2.36	$ 2.64		$ 2.72
2012	2.39	$ 2.67		$ 2.75
2013	2.35	$ 2.63		$ 2.71
2014	2.37	$ 2.65		$ 2.73
2015	2.39	$ 2.67		$ 2.75

Source: (1) -- Annual Energy Outlook, 1997
(2) -- Arizona prices are assumed to be 12% above regional forecast. See Page 2 of 2.

Historical prices of gas used for electric generation (Mountain Region)
($/Mcf nominal)

	1991	1992	1993	1994	1995	1996	
Mountain	$ 1.87	$ 2.07	$ 2.48	$ 2.09	$ 1.74	$ 2.33	
Arizona	$ 2.06	$ 2.28	$ 2.88	$ 2.23	$ 1.77	$ 3.03	
Utah	$ 1.72	$ 1.87	$ 2.31	$ 2.42	$ 2.26	$ 1.83	
Nevada	$ 1.78	$ 1.91	$ 2.45	$ 1.99	$ 1.71	$ 2.12	
New Mexico	$ 1.73	$ 1.99	$ 2.23	$ 1.99	$ 1.57	$ 2.31	
Wyoming	$ 3.51	$ 3.33	$ 3.44	$ 5.80	$ 8.32	$ 12.59	
Montana	$ 4.33	$ 3.30	$ 2.83	$ 1.21	$ 3.84	$ 2.89	
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	
Colorado	$ 2.14	$ 2.14	$ 2.53	$ 2.21	$ 1.74	$ 2.09	
AZ-Mount	$ 0.19	$ 0.21	$ 0.40	$ 0.14	$ 0.03	$ 0.70	Average
(AZ-Mou)/Mou	10%	10%	16%	7%	2%	30%	12%

Source: EIA, 1996, Natural Gas Annual

NYS PSC CASE
NO. 96 E-0898
RG&E RESTRUCTURING

SCHEDULE H

RETAILING FUNCTIONS

Notes:

(1) *P* = Primary responsibility for function. *S* = Secondary responsibility for function. Relationship to be governed and further clarified by Operating Agreement under distribution tariff.

(2) The relationship between the ISO/PE (Independent System Operator/Power Exchange) and the disco is not yet clear. For purposes of developing a complete list of LSE/disco activities, the disco is assumed to act as a local extension of the ISO/PE for activities required to maintain system reliability and security.

(3) Functions that are the sole responsibility of the disco have been eliminated from this list.

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
1. System requirements forecasting, planning, and budgeting (Forecast future energy delivery system capability/ infrastructure requirements. Prepare detailed plans and budgets to modify system to meet requirements.)	*S* Provide energy sales forecasts for disco aggregation	*P* All activities
2. Energy system work management, including prioritization, scheduling, and coordination (Prioritize, schedule, and coordinate the efficient use of labor and materials to meet customer requests, as well as the construction and maintenance of the energy system.)	*S* Work with disco to set emergency and non-emergency work priority and response time guidelines	*P* All activities
3. Design and documentation of system operating rules, operating agreements, and operating procedures (Manage real-time construction and maintenance of the delivery system, agreements with energy suppliers and the ISO with respect to delivery and receipt of energy, protection of the system during extreme operating conditions such as load shedding, voltage and pressure reductions, and requests for fuel switching and curtailment of gas or electric usage.)	*S* Work with disco to design operating rules, agreements, and procedures	*P* All activities
4. Negotiation and administration of contracts for balancing and ancillary services (Ancillary services required for secure and reliable delivery of energy; balancing services to cover variances between real-time deliveries and real-time energy consumption. Includes accounting and invoice processing support.)	*S* May contract with a non-disco provider for some ancillary services, as provided by FERC rules	*P* All activities

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
5. Short term forecasting and scheduling of system energy requirements (Daily, monthly, and seasonal energy forecasts, short-term scheduling of energy receipt and delivery, short-term scheduling of balancing and ancillary services.)	S Produce daily, monthly, and seasonal energy forecasts for customers with real-time meters. Schedule deliveries to disco interchange point/ city gate based on those forecasts, and based on load shapes for customers without real-time meters.	P All other activities, including developing standard load shapes and load-shape-based forecasts for use by LSEs where real-time meters are lacking; forecasting total system energy requirements; and aggregating LSE delivery schedules to determine requirements for load balancing and ancillary services.
6. Real-time control and monitoring of the energy delivery system (Real-time use of energy balancing and ancillary services, real-time interaction with ISO and third-party suppliers of energy, real-time application and enforcement of system operating rules, operating agreements, and operating procedures, real-time interpretation of SCADA information)	S Respond to disco/ISO operating requirements real-time	P All other activities
7. Energy imbalance management and coordination for the distribution area (Identify imbalances, trade imbalances, acquire or curtail energy supply to resolve imbalances, allocate imbalance costs, set imbalance performance standards and monitor compliance among market participants, acquire and manage/process real-time customer meter data for imbalance diagnosis)	S Provide data as required by agreement with disco	P All other activities
8. Management of system restoration (Performance of tasks required to analyze, coordinate, schedule, and facilitate restoration of the energy supply system in a timely, safe manner.)	S Provide personnel and resources to support restoration activities	P All other activities

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
9. Dispatch of field personnel for unscheduled energy system work (To respond to same-day requests for customer service and response to emergency or outage situations.) *Note:* This may include repairs of equipment and facilities on the customer side of the meter if such repairs will facilitate a rapid return to service.	*S* Depending on terms of agreement with disco, may receive first customer notification of outages or emergencies, may dispatch field personnel to make initial diagnosis of problem, may dispatch field personnel for repairs of customer-side-of-the-meter equipment and facilities.	*P* All other activities, possibly including tracking of costs for charge-back to customer's LSE
10. Real-time response to customer service and field personnel inquiries for energy delivery facilities' information (Provide data for stake-outs and to respond to such customer requests as when they can expect to return to service after an outage. Future customer requests could address such customer issues as interruptions of customer/generator bilateral contracts for operating reasons.)	*S* Depending on terms of agreement with disco, may provide interface between direct retail customer query and disco.	*P* All other activities
11. Coordination and maintenance of emergency response plans and training (Develop, coordinate, and document emergency response plans, and associated training requirements, including emergency response drills.) *Note:* Emergencies include, for example, wire-down reports (including phone and cable wire-downs), individual or local service outages, large-scale service outages (e.g., ice storms), pole and cable hits, and pipe dig-ups.	*S* Participate in development of emergency response plans and ensure personnel are trained as agreed by LSEs and disco	*P* All other activities
12. Deliver energy from the city gate/interchange point to the end-user	*S* Schedule energy deliveries (plus losses) to city gate/interchange point and inform disco accordingly	*P* All other activities

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
13. Distributed generation/back-up generation/buy-back power management of interaction with energy system (Identify interface requirements, accommodate partial and full outages of customer-sited generation, analyze and resolve power quality and system operating issues due to such generation, set and enforce performance standards.) *Note:* It is not clear whether the LSE or disco would be best positioned to have ultimate authority and accountability over customer-sited generation.	S Purchase all power from customer generators (not sold to other LSEs) and provide back-up power. Depending on agreement with disco, may interface between disco and customer.	P Set and enforce interface requirements, including imposing non-performance penalties.
14. Power quality (Accept customer calls, diagnose problems, determine problem accountability (calling customer, other customers, disco facilities), prioritize, schedule, and coordinate problem resolution, implement problem resolution.) *Note:* Power quality may require a collaborative approach among some or all LSEs, the disco and customers and providers with power quality concerns to address multi-customer or cross-customer issues.	P All other activities	S Provide diagnostic support upon LSE request, and resolve power quality problems attributable to disco facilities or operations, including tracking costs and billing LSEs as appropriate
15. Market research (Collect, analyze, and report customer data for the support of planning and development of new and existing products and services.)	P All other activities	S Work with LSEs to unbundle wholesale distribution services to allow for product differentiation
16. Quality service management (Serve as an internal advocate for the customer; collect and analyze customer data for feedback on service performance and product quality.)	P All other activities	S Work with LSEs to set and maintain delivery service quality standards and performance

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
17. Marketing, including pricing design (Identify value through products and services to customers and customer subgroups based on needs and desires identified through market research. Coordinate cross-functional teams for product design and pricing, positioning, and promotion of the product and service.) *Note:* Does not include regulated tariffs, addressed separately below.	*P* All other activities	*S* Work with LSEs to unbundle wholesale distribution services to allow for product differentiation.
18. Sales (Prospecting, communicating, and selling products and services to customers)	*P* All activities	*N/A*
19. Maintenance of third party relationships (Maintain relationships with third parties who also have relationships with retail customers for energy or energy-related products and services.) *Note:* Includes conducting training for trade allies, working with local governments to conduct municipally-mandated undergrounding and other activities, acting on behalf of low-income customers to facilitate Department of Social Service activities, responding to fire department requests to address possible gas leaks and wire-downs, working with various disaster and emergency offices and organizations, interfacing with local governments and public interest groups, participating in IEEE standards groups, and, in the future, negotiating services, prices, performance standards, and data exchange arrangements with LSEs.)	*S* Maintain relationships with discos, other LSEs, and joint ventures/alliances/ suppliers.	*P* Maintain relationships with emergency- and safety-related organizations, LSEs, suppliers, and DSS and other parties involved in providing funding for services to retail customers who can't pay full price for them.
20. Responding to customer inquiries and requests (Includes turn-on/shut-off, requests for outage-related information, application processing, requests for account information, and requests for information regarding energy technologies and end-uses.)	*P* All other activities	*S* Implement turn-on/shut-off. Provide information upon request concerning the status of outages whose restoration is being managed by the disco

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
21. Management of the revenue collection process (Obtain consumption information, bill customer consistent with service agreement, accept and process payments, manage delinquent accounts, maintain accuracy and integrity of customer records.) *Note:* Includes design, operations, and maintenance of CIS and other information systems infrastructure.	P Conduct this task at the retail level, for revenue collected directly from retail customers	S Conduct this task at the wholesale level, for revenue collected from LSEs
22. Facilitation of customer trading of imbalances and storage balances (Provide customers with an efficient means of engaging in transactions with other customers to mitigate expense associated with energy imbalances.) *Note:* Responsibility and practices may be different for gas and electricity.	P Conduct this task at the retail level, for retail customers with real-time meters who have been given the option in their retail product design of avoiding the flow-through of wholesale imbalance charges	S Conduct this task at the wholesale level, for LSEs only
23. Development and implementation of public involvement programs (Communicate with the general public for purpose of education, information exchange, and to address customer complaints which may otherwise elevate to a PSC complaint.) *Note:* To facilitate development of the competitive retail market, all customer-interface activities should eventually be conducted by the LSE rather than the disco.	P All other activities	S Provide funding through public policy charge
24. Regulatory coordination and tariff design (Serve as the liaison between the Company and regulatory bodies, design tariffs, conduct rate cases.) *Note:* Disco and regulated LSE will remain under rate-of-return and other State regulation.	S Regulated LSE will have retail tariff responsibilities that competitive LSEs will not. All LSEs may need to comply with licensing and reporting requirements.	P Wholesale distribution tariff and other regulatory coordination activities.

Functions	Load-Serving Entity Responsibilities	Disco Responsibilities
25. Forecasting of customer energy requirements (Forecasting of electric system and installed reserve capacity and energy required to meet customer demand for electric energy, including forecasts for specific groups and/or individual customers as required by future service/tariff designs. Forecasts can be daily, monthly, seasonally and/or long-term.)	*P* All other activities	*S* Aggregate LSE forecasts and produce total system load forecasts for distribution system planning and imbalance service requirements
26. Scheduling of capacity and energy purchases and delivery to the service area (Capacity (e.g., installed reserve) and energy procurement and delivery scheduling consistent with forecasts of customer requirements.) *Note:* Responsibility and practices may be different for gas and electricity.	*P* All other activities	*S* Scheduling of spot market energy purchases and stanc by capacity to eliminate local loac imbalances
27. Negotiation and administration of contracts for procurement of energy and associated delivery services (Consistent with forecasted capacity and energy requirements, negotiate contracts for the procurement of capacity, energy, and wholesale delivery services. Administration of the contracts includes accounting and invoice processing support.) *Note:* Assumes that LSEs are responsible for pipeline and installed reserve capacity to meet their customers' needs. It may be that electric installed reserves are more efficiently purchased by the disco for its service area load and passed through in the wholesale distribution tariff.	*P* All other activities	*S* Capacity and energ contracts associatec with long-term imbalance trends.

Tellus Institute
Strandable Costs Calculation Model

1. Introduction

This document serves as a guide to the Tellus Institute approach to calculating strandable costs for an electric utility. It provides an overview of the methodology, inputs, and scenario development used in calculating utility-specific strandable costs. To facilitate the strandable costs calculation, a simple model was developed consisting of four interdependent analyses: an unbundling analysis, a market price analysis, a financial evaluation of strandable costs in a single year, and a projection of strandable costs over a specified period of analysis. Since each utility faces a unique set of circumstances entering into the competitive generation market, the Tellus Strandable Costs Model (SCM) is designed to provide an analysis of the specific financial conditions for each utility.

It is important to recognize that any estimates of strandable costs will include many uncertainties, and will be subject to debate by many parties. Therefore, estimates of strandable costs should be as simple and as clear as possible. This information guide is intended to explain Tellus' SCM modeling assumptions and should assist readers in following the logic of the calculations in the model. In addition, Tellus recommends that SCM estimates should be prepared for a variety of scenarios and sensitivities to indicate how the stranded costs might change with different input assumptions.

2. Methodology

Strandable costs can generally be defined as the difference between the competitive market value and the regulated book value (or embedded cost value) of a utility's generation assets. Therefore, the general approach to estimating strandable costs is to calculate the difference between (a) the utility's embedded generation cost value over a specified period of time, and (b) the market price for power in the region over the same period of time. The SCM follows from this basic equation. As such, the SCM calculates a utility's *potentially strandable* costs, as opposed to costs that would actually be stranded (e.g., as a result of customers actually leaving the utility's system for an alternative supplier). Strandable costs represents the maximum amount of costs that may become stranded in a retail competitive generation market.

The SCM includes four main components: a market price calculation; an unbundling calculation of the utility's average retail generation price; a calculation of strandable costs in the base year; and a projection of strandable costs over a user specified period of analysis.

Market Price Calculation

The user can choose from three different methods to determine the average generation market price value for the first year of analysis, based on: 1) a least cost mix of new natural gas combined cycle and combustion turbine generating units; 2) user-specified capacity and energy charges; or 3) an exogenous user-input value. In all cases, the estimate of market price is based on the assumption that competitive generation companies in the utility's region provide energy sufficient to meet the utility's entire load. In other words, the market price represents the average cost of power in the region, as opposed to the marginal cost.

The first option derives a competitive market price based on the cost of an optimal combination of new natural gas combined cycle and combustion turbine units. This method requires the user to make assumptions about current and future fuel (gas) prices, a discount rate, and fixed charge factor. A real levelized average market price based on this CC/CT mix represents the market price for the first year of analysis.

For the second option, the competitive market price is based on user-specified energy and capacity charges. Specific energy and capacity price information could be based on existing state or regional market price proxy values, such as competitive wholesale prices, avoided cost values, etc.

Finally, the user has the option of simply entering an exogenous, average market price value.

Unbundled Generation Costs

The user enters utility-specific costs and revenues for a historical year using information provided by utilities to FERC. Unbundled costs are calculated by allocating the data into generation, transmission, distribution, and customer related expenses, according to FERC accounting categories. After the expenses and revenues are spread among these categories, further adjustments are made regarding wholesale transactions to produce a final estimate of embedded costs per category. An average unbundled rate (in cents/kWh) for each component is then computed by dividing embedded costs by ultimate sales to customers.

Strandable Costs - Base Year

Strandable costs for the first year of analysis are calculated based on a comparison of the utility's unbundled generation rate and the assumed market price. The user has the option of assuming a transition charge, which allows the utility to recover from customers a portion of stranded costs. The "net" revenue reduction represents the strandable costs, less any revenues recovered through the transition charge. The utility's net revenue reduction is then compared to how it will impact the utility's shareholders, as well as its average retail customer.

Strandable Cost - Projections

Finally, the SCM allows the user to develop scenario projections based on a fixed time horizon (not to exceed 10 years). The method for determining the market price over the projected time period will depend on whether or not the utility has excess capacity, and if that excess capacity is anticipated to end during the period of the analysis. If the utility does have excess capacity which is expected to end within the period of analysis, then regardless of what method is used to calculate market price in the base year, the model will automatically switch to the CC/CT Mix market price in the year that excess capacity ends, since this price will best represent the marginal cost of generation in the future. In that year, the CC/CT Mix market price will reflect a price that is escalated from the base year CC/CT Mix price according to user's assumed escalation rates for fuel, energy and fixed cost components.

Regardless of which market price methodology is used, the user can make assumptions about escalation rates for the various market price components (e.g., energy and demand charges). The user may also choose to enter an escalation rate for the utility's average unbundled generation price projection. And finally, the user may estimate the utility's future electricity sales either by entering a forecast of sales over the projection period or by escalating the base year sales at a specified rate.

The computation and inputs for the SCM are discussed in greater detail below.

3. Inputs and Computational Analysis

The inputs necessary to calculate strandable costs will come from a number of utility-specific and industry-specific sources. Examples of such sources are: the utility's FERC FORM 1, current utility Integrated Resource Plans and Annual Reports, and various fuel cost forecasts, and supply and demand forecasts for the region.

Unbundling Generation Costs

The first step in the valuation of a utility's existing generation assets is to isolate those costs and revenues which are associated with generation-related assets. To do this, the models' unbundling input spreadsheet requires that information from the utility's Operating Income (FERC FORM 1 pp. 114-119), Electric Operation and Maintenance Expenses (FERC FORM 1 pp. 320-323), Customer Sales and Operating Revenues (FERC FORM 1 pp. 300-304), and Electric Utility Plant (FERC FORM 1 pp. 220-221) be entered as inputs.

The model uses a simple method to unbundle these costs and revenues by allocating the Operation & Maintenance Expenses, Plant Related Expenses, and Operating Revenues in rate base into generation-related, transmission-related, distribution-related and customer-related costs and revenues, according to each category's contribution to net plant (or gross plant in the case of depreciation). In the case of Administrative and General Expenses, the user has the option to directly allocate these costs to any of the four cost components.

Total Operating Revenues represent the value of assets in rate base, for both wholesale and retail operations. In order to obtain the utility's total *retail* revenues, a wholesale revenue adjustment must be made to Total Operating Revenues. The Adjusted Retail Revenues are then converted to an average retail rate (cents/kWh) per cost component by dividing the totals by total retail sales. The final result is an estimate of unbundled generation, distribution, transmission, and customer costs for the utility's retail operations.

Market Price

Estimating a competitive market price for a specific state or region is likely to be highly uncertain. In order to accommodate different levels of information about the market price for power, the model allows for three market price options to be pursued and examined in separate scenarios.

As discussed earlier, the first option utilizes cost information for a newly built Combustion Turbine (CT) and a newly built Combined Cycle (CC) plant to determine a market price based on the optimal mix of CTs and CCs to serve the utility's load profile. This estimation of market price is likely to represent a "high" market price value. The model offers the user the option to input plant-related cost information for a new CC or CT, or to simply use the default values provided from the *EPRI Technical Assessment Guide*. In addition, financial assumptions such as the fixed charge factor, and fuel cost escalation and inflation rates may be input or default values may be used.

To determine the likely future mix of CCs and CTs for a utility's system, the SCM conducts a crossover calculation, based on a comparison of fixed and variable costs, to determine the capacity factor below which CTs will operate and above which CCs will operate. The outcome of the crossover calculations provides the combination of CCs and CTs which would serve this utility's system at the lowest cost, optimal or least cost system. In order to correctly compare the unbundled generation rate to the CC/CT market price in the strandable costs comparison, it is necessary to adjust the CC/CT market price to reflect the generation-related A&G costs the utility would likely incur in providing this electricity, just as they are reflected in the unbundled generation rate. The amount of the CC/CT market price A&G adjustment is based on the historical cost of generation related A&G, as reflected in the unbundling spreadsheet.

The second market price option allows for the choice of representative energy and demand charges to be input. Using these charges, along with the utility's load data, the model calculates the average market generation price in costs/kWh. Using this method, the user can create a range of high, medium, and low market prices assumptions that are derived from a range of user input energy and demand charges.

The third market price option simply allows the user to directly input a market generation price (in cents/kWh). Again, with this straightforward method, the user can create a range of market price assumptions.

Strandable Costs - Base Year

Once the unbundled generation costs for the utility have been estimated by the model, and a market price has been estimated, strandable costs for the base year can be calculated as the difference between the two. The model presents the output for a one year strandable cost calculation. The model calculates the net reduction in generation costs (in ¢/kWh) as the difference between the average utility generation cost and the competitive market price. If a transition charge is assumed, then the net reduction in generation costs will be reduced accordingly. Finally, retail sales are used to determine the strandable costs (i.e., revenue reduction) in this one year.

In turn, the model examines the impact on the shareholders by examining the Revenue Reductions due to competition as a percentage of the following costs:

- Net Income plus Income Taxes (or Gross Income)
- Gross Income plus Depreciation
- Gross Income plus Depreciation and Net Interest.

The first comparison is likely the most important, since the financial viability of a utility is typically measured in terms of its ability to pay its shareholders and its income taxes. A scenario in which there would be a sharing of stranded costs (e.g., using a transition charge) would clearly alleviate the impact on shareholders, yet not provide as a large reduction in the average generation rate to ratepayers.

4. Strandable Costs - Projections

The SCM allows for scenarios that calculate potential strandable costs over a multiple year period. The importance of analyzing this information is that while the first year may reveal significant initial strandable costs for a utility, the utility's strandable costs over a longer period of analysis may provide an entirely different picture. For example, a utility with stranded costs in the base year may, within a few years, face no strandable costs, and may even receive profits as a result of its embedded generation costs falling below expected future market prices.

In this multi-year period analysis, the user first selects the time period for the projection, and identifies the year that excess capacity, if it exists, is anticipated to end. If excess capacity is exhausted within the projection period, the CC/CT market price takes effect in at that point in time. If no new capacity is needed within the projection period, then the market price assumed in the base year is simply escalated over the period of analysis based on a user specified escalation rate.

Depending on the market price methodology, selected escalation rates must be entered:

- CC/CT mixed price: escalation rates for Fuel Costs, Capital Costs, and O&M costs.
- Energy and Capacity Charges: escalation rates for the energy and capacity charges.
- Exogenous market price: Escalation rate for the exogenous ¢/kWh market price.

In addition to market price escalation data, escalation rates can be applied to the utility's average retail generation price and its retail sales in the base year.

Once the model calculates the projection of strandable costs, the sum of the strandable costs stream is converted to net present value. In a final important step, an adjustment is made to reflect the net present value of the generation-related regulatory assets not yet in ratebase. The sum of the stream of strandable costs and the potentially strandable regulatory assets, both in terms of net-present value, is the total potential strandable costs.

Based on a series of assumptions about the future costs of fuel, the increase in the market price over time, and the option to consider a transition charge, a full range of strandable cost sensitivities may be examined.